BEFORE THE STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BOARD OF PUBLIC UTILITIES

I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF AN INCREASE IN GAS RATES, DEPRECIATION RATES FOR GAS PROPERTY, AND FOR CHANGES IN THE TARIFF FOR GAS SERVICE, B.P.U.N.J. NO. 13, GAS PURSUANT TO N.J.S.A. 48:2-18, 48:2-21 AND 48:2-21.1	)	**BPU DKT. NO. GR05100845** **OAL DKT. NO. PUC-1747-06**

TESTIMONY OF MATTHEW I. KAHAL
ON BEHALF OF THE
NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. I am employed as an independent consultant retained in this matter by the Division of the Ratepayer Advocate (Ratepayer Advocate). My business address is 5565 Sterrett Place, Suite 310, Columbia, Maryland 21044.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I hold B.A. and M.A. degrees in economics from the University of Maryland and have completed course work and examination requirements for the Ph.D. degree in economics. My areas of academic concentration included industrial organization, economic development and econometrics.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have been employed in the area of energy, utility and telecommunications consulting for the past 25 years working on a wide range of topics. Most of my work has focused on electric utility integrated planning, plant licensing, environmental issues, mergers and financial issues. I was a co-founder of Exeter Associates, and from 1981 to 2001 I was employed at Exeter Associates as a Senior Economist and Principal. During that time, I took the lead role at Exeter in performing cost of capital and financial studies. In recent years, the focus of much of my professional work has shifted to electric utility restructuring and competition.

Prior to entering consulting, I served on the Economics Department faculties at the University of Maryland (College Park) and Montgomery College teaching courses on economic principles, development economics and business.

A complete description of my professional background is provided in Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have testified before approximately two-dozen state and federal utility commissions in more than 250 separate regulatory cases. My testimony has addressed a variety of subjects including fair rate of return, resource planning, financial assessments, load forecasting, competitive restructuring, rate design, purchased power contracts, merger economics and other regulatory policy issues. These cases have involved electric, gas, water and telephone utilities. In 1989, I testified before the U.S. House of Representatives, Committee on Ways and Means, on proposed federal tax legislation affecting utilities. A list of these cases may be found in Appendix A, with my statement of qualifications.

Q. WHAT PROFESSIONAL ACTIVITIES HAVE YOU ENGAGED IN SINCE LEAVING EXETER AS A PRINCIPAL IN 2001?

A. Since 2001, I have worked on a variety of consulting assignments pertaining to electric restructuring, purchase power contracts, environmental controls, cost of capital and other regulatory issues. Current and recent clients include the U.S. Department of Justice, U.S. Air Force, U.S. Department of Energy, the Federal Energy Regulatory Commission, Connecticut Attorney General, Pennsylvania Office of Consumer Advocate, New Jersey Division of the Ratepayer Advocate, Rhode Island Division of Public Utilities, Louisiana Public Service Commission, Arkansas Public Service Commission, Maryland Department of Natural Resources and Energy Administration, and MCI.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES?

A. Yes. I have testified on cost of capital and other matters before the Board of Public Utilities (Board or BPU) in gas, water and electric cases during the past 15 years. A listing of those cases is provided in my attached Statement of Qualifications. Most recently, I testified on capital structure and financial issues in the pending Public Service Enterprise Group/Exelon Corporation merger docket (BPU Docket No. EM05020106).

II. OVERVIEW

A. Summary of Recommendation

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by the Division of Ratepayer Advocate (Ratepayer Advocate) to develop a recommendation concerning the fair rate of return on the gas distribution rate base of Public Service Electric and Gas Company (PSE&G or the Company). This includes both a review of the Company's proposal concerning rate of return and the preparation of an independent study of the cost of common equity. I have provided my recommended rate of return to the Ratepayer Advocate's revenue requirement witness in this case, Mr. Robert Henkes.

Q. WHAT IS THE COMPANY'S PROPOSAL IN THIS CASE?

A. As presented on Schedule ANS-37 R-1, PSE&G proposes an overall rate of return of 8.51 percent, based on its "actual" capitalization at September 30, 2005. The capital structure proposed in this case includes 50 percent common equity, 48 percent long-term debt and small amounts of preferred stock and customer deposits. The overall rate of return is sponsored by Mr. Stellweg, and the 11.0 percent return on equity is sponsored by PSE&G's outside witness, Dr. Roger Morin.

Although Mr. Stellweg refers to the proposed capitalization as "actual," in fact it reflects certain adjustments to actual data. First, it excludes the Company's "securitization" debt since that debt was directly assigned to the financing of certain assets relating to electric service. I do not object to the proposed removal of securitization debt. Second, Mr. Stellweg excludes $322 million of long-term debt that is scheduled to mature within one year, but he ignores the replacement long-term debt. Third, he omits short-term debt from the capital structure used for ratemaking. I do not agree with these latter two deletions from capital structure in this case.

Q. WHAT IS THE COMPANY'S CURRENTLY AUTHORIZED RATE OF RETURN ON EQUITY FOR RETAIL SERVICE?

A. PSE&G provides retail gas and electric distribution service regulated by this Board, and wholesale electric transmission service regulated by the Federal Energy Regulatory Commission (FERC). In the Company's last gas and electric rate cases, PSE&G's rate of return on equity was set at 9.75 percent for electric service and 10.0 percent for gas service. It is noteworthy that in the last case, the Company included a ratemaking "actual" capital structure (at June 1, 2001) with a 38.4 percent common equity ratio, substantially more leveraged than its currently proposed capital structure. (See response to SRR-39.) Thus, in this case, the Company seeks a large increase in its authorized rate of return on equity compared to its currently-authorized electric and gas returns for retail service, even though its proposed equity ratio has increased from 38 to 50 percent.

Q. DOES THE COMPANY INTEND TO UPDATE ITS POSITION ON RATE OF RETURN?

A. That is not clear at this point. Dr. Morin states that if he does submit a rate of return update, it would be provided two weeks before the hearings in this case, and the update would occur "should capital market conditions warrant such an update." (Response to RAR-ROR-1) Under the current schedule, that would imply an update submitted on July 7, 2006.

Q. WHAT IS YOUR RECOMMENDATION AT THIS TIME ON RATE OF RETURN?

A. As presented on Schedule MIK-1, I am recommending a return on PSE&G's gas distribution rate base of 7.66 percent, which includes a 9.5 percent return on common equity. The 9.5 percent figure is based primarily upon a discounted cash flow (DCF) study of a comprehensive group of gas distribution companies that I believe are reasonably comparable to PSE&G. In addition, I have made three other modifications to the Company's overall rate of return proposal. I disagree with Mr. Stellweg's decision to remove the $322 million in long-term debt that is due to mature in one year. This is improper, since in this case PSE&G plans to replace all of this maturing debt with new long-term debt, which he has ignored. Restoring the $322 million in maturing debt to capitalization also results in a small increase in the embedded cost of long-term debt (from 6.09 to 6.19 percent). Finally, I have included $143 million in short-term debt (about 2 percent of total capital), based on a 24-month average. With these corrections, I am recommending a capital structure of 46.4 percent common equity and 52 percent total debt. This recommendation is summarized on Schedule MIK-1.

Q. DO YOU EXPECT TO UPDATE YOUR ANALYSIS?

A. Yes, I will provide updated market information in July, although I cannot at this time state whether doing so will alter my recommendation. My DCF analysis incorporates market data extending through April 2006, and by July I expect to have available May and June market data that can be incorporated.

B. <u>Capital Cost Trends</u>

Q. HAVE YOU REVIEWED THE TRENDS IN MARKET CAPITAL COSTS OVER THE PAST DECADE?

A. Yes. Schedule MIK-2 shows capital cost indicators on an annual basis since 1992 and on a monthly basis during January 2002 to May 2006. The indicators include inflation (as measured by the annual change in the Consumer Price Index), short-term Treasury yields, ten-year Treasury yields and single A-rated long-term utility bond yields (per Moody's).

This schedule shows that despite year-to-year fluctuations there has been a clear downward trend in capital costs over this time period, at least for long-term securities. Short-term interest rates tend to be governed by Federal Reserve (Fed) policy, and during the last two years the Fed has been "tightening" (i.e., raising short-term rates) in response to a strengthening U.S. economy. As measured by utility bond yields, it appears that capital costs "bottomed out" in mid-2005, with single A yields reaching a low point in the mid 5 percent range. Long-term interest rates remained extremely low through the early part of 2006 (i.e., long-term utility bond yields below 6 percent), but in the last calendar quarter, they have moved up somewhat. Current, long-term Treasury yields are at approximately 5 percent, and single A utility bond yields are in the 6 to 6.5 percent range.

Despite this very recent upward movement, I would characterize the capital cost environment as remaining quite favorable compared to past years, certainly it is very favorable compared to pre-2004 and 2005, the years when PSE&G's last electric and gas rate cases were heard. Capital costs in 2006 also appear to be favorable compared to the late 1990s.

Q. ACCORDING TO SCHEDULE MIK-2, THERE APPEARS TO BE A RECENT UPWARD MOVEMENT IN INFLATION. PLEASE COMMENT.

A. Inflation rates during the past year have moved upwards in response to price spikes for energy. However, the underlying "core" inflation (excluding the volatile fuel and food sectors) remains relatively stable. For example, the long-term forecast of the GDP Deflator (Blue Chip Economic Indicators, March 2006) is 2.1 percent annually. The favorable "core" inflation outlook is based on strong productivity growth in the U.S. economy, the expansion global competition which tends to hold down increases in U.S. product prices and Fed monetary policy that emphasizes inflation control.

Q. YOUR SCHEDULE MIK-2 PROVIDES DATA ON LONG-TERM INTEREST RATES. IS THIS INDICATIVE OF COMMON EQUITY COST RATES?

A. At least in a general sense, I believe it does. The forces over time that lead to lower yields on long-term debt also favorably affect the cost of equity, although I would acknowledge that equity and debt cost rates do not necessarily move together in lock step. The favorable trends over time in long-term debt cost rates are also likely to affect PSE&G's equity cost rate for gas service. That cost rate today undoubtedly is lower than it was at the time of the Company's last electric and gas rate cases.

There is another force at work that further contributes to a reduced cost rate for equity -- federal tax policy. In mid-2003, Congress enacted legislation granting favorable income tax treatment for dividend payments and capital gains. (Legislation extending this favorable tax treatment was enacted by Congress earlier this year.) Lower taxes on returns to equity investments mean that investors are willing (or should be willing) to accept lower returns for holding common stocks (such as that of PSE&G's parent), particularly as compared with bonds, which do not enjoy this benefit. The DCF method, which uses relatively current market data, can capture this effect. Other methods, such as historical risk premium methods, may not be able to do so.

Q. HOW WOULD YOU CHARACTERIZE PSE&G'S RISK PROFILE?

A. PSE&G's risk profile is generally viewed favorably. The Company has a triple B corporate rating with its senior secured bonds rated low single A. The Company's capital structure has strengthened significantly since its last set of retail rate cases, and its embedded cost of debt has been declining. This combination has given rise to strong and improving cash flow measures, which are important for credit quality. In fact, PSE&G has indicated that it can fund its utility construction program from internally generated cash, with new debt issuances used to fund maturing debt.

As Moody's most recent credit rating report summarizes:

> PSE&G's A3 senior secured rating reflects the relatively low business risk of its T&D [electric and gas transmission and distribution] operations, a reasonable regulatory environment, and a financial profile that is adequate for its rating. (April 21, 2006)

I conclude from this that PSE&G's regulated retail gas and electric operations are viewed favorable from a risk perspective. However, I make no specific risk adjustment for PSE&G versus an industry group of gas utilities that I use in this case for cost of capital purposes.

C. Testimony Organization

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section III is a brief discussion of the capital structure, cost of debt and overall rate of return recommendation. I describe my adjustments to the Company's proposal in that section.

Section IV presents my independent cost of equity studies that serve as the basis for my return on equity recommendation. This includes my primary study, a DCF study of a gas distribution industry group. I also present an electric delivery service DCF study as a check on the gas distribution study and a Capital Asset Pricing Model (CAPM) study. While these latter two studies may have some value as a comparison or check on my primary DCF evidence, the gas distribution study serves as the principal basis for my recommendation.

Section V provides my critique to Dr. Morin's cost of equity evidence and recommendation. My main area of disagreement is with his risk premium/CAPM evidence rather than his DCF study. In addition, I do not see a need in this case to include an upward adjustment for flotation expense, as Dr. Morin has done.

III. CAPITAL STRUCTURE AND OVERALL RETURN

Q. WHAT IS PSE&G'S PROPOSAL CONCERNING OVERALL RATE OF RETURN?

A. Company witness Mr. Stellweg bases the Company's rate of return request on what he identifies as the "actual" capital structure at September 30, 2005. This capital structure has 50 percent common equity, 48 percent long-term debt, 1.3 percent preferred stock and 0.7 percent customer deposits. (Source: Schedule ANS-37 R-1) Although this is identified as an "actual" capital structure, it omits three items from the balance sheet: (1) securitization debt; (2) long-term debt maturing within one year; and (c) short-term debt. This capital structure, in combination with Dr. Morin's 11.0 percent return on equity, produces his recommended 8.51 percent overall return on rate base.

Q. ARE YOU RECOMMENDING ANY CHANGES TO THE PROPOSED RATEMAKING CAPITAL STRUCTURE?

A. I am recommending two changes to the proposed capital structure. The $322 million of long-term debt (excluded due to its "current maturities" status) should be retained. (In the alternative, I would not object to omitting that debt and instead adding the debt that PSE&G has issued or will issue to replace the maturing debt.) Second, the ratemaking capital structure should reflect short-term debt, and I have included $143 million of short-term debt (a 24-month average) at 4.8 percent (the latest reported short-term debt cost rate). Retaining the $322 million of the excluded debt in capital structure increases the embedded cost of debt from 6.09 to 6.19 percent, since PSE&G shows that this debt carries a higher cost rate, on average, than its other debt.

I have no objection to the Company's decision to exclude securitization debt. That debt clearly is unrelated to PSE&G's gas operations, and in fact, is directly assigned to specific regulatory assets associated with electric restructuring.

Q. WHY IS IT IMPROPER TO EXCLUDE THE LONG-TERM DEBT DUE TO MATURE IN ONE YEAR?

A. It may not necessarily be unreasonable to exclude that debt if the utility also proposes the inclusion of the replacement debt. In that case, the utility's treatment could be considered to be a pro forma adjustment or update. The problem in this case is that PSE&G has excluded the $322 million of debt maturing in 2006, while omitting the debt that it will add in 2006 to replace the maturing debt. This omission occurs in Mr. Stellweg's supporting workpapers but is not explained.

Q. DOES PSE&G, IN FACT, EXPECT TO REFINANCE THE MATURING DEBT?

A. Yes, it does. The response to RAR-ROR-6 identifies both the $322 million of debt maturities and $425 million of new issuances scheduled to occur in 2006. The purpose of the new long-term debt issues clearly is to refinance the maturing debt.

Q. IS IT COMMON PRACTICE IN YOUR EXPERIENCE TO ELIMINATE MATURING DEBT FROM CAPITAL STRUCTURE WITHOUT GIVING RECOGNITION TO THE REPLACEMENT FINANCING?

A. Based on my experience, this is not common practice since doing so could significantly misrepresent the debt balance and capital structure.

Q. WHY WOULD THIS PRACTICE MISREPRESENT CAPITAL STRUCTURE?

A. I can explain with an example. Consider a simplified case of a utility with $1 billion of long-term debt, with all debt having a maturity of five years, and with one fifth maturing each year. To keep the example simple, assume the utility's capital investment and capital structure are stable. This means that $200 million in debt will mature each year and will be promptly replaced by $200 million of new debt. Thus, on each December 31, the utility would report $1 billion of debt, with $200 million of that classified as current maturities. Absent a significant lag between debt maturing and replacement, the utility would continually be using $1 billion of long-term debt to finance its capital investment. However, following PSE&G's approach, $200 million of debt -- which is essentially continuously on the balance sheet on an ongoing basis -- is simply ignored for ratemaking purposes. This method systematically understates the utility's actual usage of debt and debt ratio and overstates its common equity ratio. As this example illustrates, the $1 billion is the right level of debt to use for ratemaking capital structure.

Q. WHAT IS YOUR RECOMMENDATION FOR SHORT-TERM DEBT?

A. It seems clear that PSE&G makes significant use of short-term debt to finance its operations, although the level of short-term debt can fluctuate from month-to-month based on operational needs. For capital structure purposes, I have used $143 million (2.2 percent of total capital), based on the 24-month average ending February 2006. (Response to RAR-ROR-4) Please note that the September 30, 2005 actual figure was $185 million, and the average for the 12 months ending September 2005 was $193 million. I used a 24-month average in an attempt to obtain a reasonable, normal on-going amount of short-term debt.

Q. DOES PSE&G RECOGNIZE THE IMPORTANCE OF SHORT-TERM DEBT AS A SOURCE OF FINANCING?

A. Yes. This was emphasized by Joint Applicants' witness financial John Young in the pending PSEG/Exelon merger case. In emphasizing the importance of PSE&G's participation in the proposed Money Pool, he states: "Going forward, PSE&G estimates its average short-term debt balances will be in the $200 million plus range." (Young, Rebuttal, page 4, Docket No. EM05020106) My $143 million average figure is clearly conservative compared to Mr. Young's own "going forward" expectations for PSE&G.

Q. HAS PSE&G EXPLAINED WHY IT HAS OMITTED SHORT-TERM DEBT?

A. Yes. In response to RAR-ROR-10, the Company states that short-term debt is not a "financing tool to support long-term utility assets." It is further claimed that short-term debt is used to finance deferred balances, construction work in progress and "short-term capital needs."

Q. DO AGREE WITH THIS ASSESSMENT?

A. Not entirely. A utility may or may not be using short-term debt to help finance long-term utility assets. Notwithstanding that claim, it is likely that short-term debt is used from time to time by the utility due to its inherent flexibility, i.e., unlike long-term debt, short-term debt can be very quickly increased or decreased and at low cost. This makes it a very useful, economical financing tool to help manage seasonal and other cash flow fluctuations that are inherent in the utility business, particularly for gas utilities.

In the case of PSE&G's gas operations, even if one were to concede that short-term debt does not finance "long-term assets," it does finance the claimed rate base. PSE&G is seeking a claim in this case for working capital (a "short-term asset"), and specifically, seeks its inclusion in rate base. If working capital is to be included in rate base, then it certainly is appropriate to reflect a reasonable amount of short-term debt in capital structure. In this case, my $143 million average balance is 2.2 percent of total capital, which I believe is a modest level.

Q. GIVEN YOUR ADJUSTMENTS, WHAT IS YOUR OVERALL RATE OF RETURN AND CAPITAL STRUCTURE?

A. I am recommending an overall return of 7.66 percent, and a capital structure of 46.4 percent common equity and 52 percent total debt. This recommendation is summarized on Schedule MIK-1.

Q. IS THE CAPITAL STRUCTURE THAT YOU RECOMMEND REASONABLE?

A. Yes, I believe it is. The 52 percent total debt ratio falls comfortably within the range identified by Standard & Poors (S&P) for a single A rating for a utility with PSE&G's "3" Business Position.[1] The 46.4 percent common equity ratio also compares favorably with the 42.2 percent common equity ratio of the gas distribution utility group that I use in this case. (See Schedule MIK-3, page 1 of 2) The capital structure that I am recommending is financially sound and comports with the manner in which PSE&G is actually financed at September 30, 2005.

[1] For Business Position 3, S&P identifies a benchmark range of 50-55 percent total debt for a single A rating. (June 2, 2004 benchmarks)

IV. COST OF COMMON EQUITY

A. Using the DCF Model

Q. WHAT STANDARD ARE YOU USING TO DEVELOP YOUR RETURN ON EQUITY RECOMMENDATION?

A. As a general matter, the ratemaking process is designed to provide the utility an opportunity to recover its (prudently-incurred) costs of providing utility service to its customers, including the reasonable costs of financing its (used and useful) investment. Consistent with this "cost-based" approach, the fair and appropriate return on equity award for a utility is its cost of equity. The utility's cost of equity is the return required by investors (i.e., the "market return") to acquire or hold that Company's common stock. A return award greater than the market return would be excessive and would overcharge customers for utility service. Similarly, an insufficient return could unduly weaken the utility and impair incentives to invest.

Although the <u>concept</u> of the cost of equity may be precisely stated, its quantification poses challenges to regulators. The market cost of equity, unlike certain other utility costs, cannot be directly observed (i.e., investors do not directly, unambiguously state their return requirements), and it therefore must be estimated using analytic techniques. The DCF model is one such technique familiar to analysts and this Board.

Q. IS THE COST OF EQUITY A FAIR RETURN AWARD FOR THE UTILITY AND CUSTOMERS?

A. Generally speaking, I believe it is. A return award commensurate with the cost of equity generally provides fair and reasonable compensation to utility investors and normally should allow efficient utility management to successfully finance its operations on reasonable terms. Certainly, this has been the case for PSE&G based on the equity returns granted by the Board in recent years. Setting the return on equity equal to a reasonable estimate of the cost of equity also is fair to ratepayers.

I recognize that there can be exceptions to this general rule. For example, in some instances, utilities have sought rate of return adders as a reward for asserted good management performance. In this case, it does not appear that the Company is making any such request, and therefore the issue is one of <u>measuring</u> the cost of equity, not whether a properly measured cost of equity is fair return.

Q. WHAT DETERMINES A COMPANY'S COST OF EQUITY?

A. It should be understood that the cost of equity is essentially a market price, and as such, it is ultimately determined by the forces of supply and demand operating in financial markets. In that regard, there are two key factors that determine this price. First, a company's cost of equity is determined by the fundamental conditions in capital markets (e.g., outlook for inflation, monetary policy, changes in investor behavior, investor asset preferences, etc.). The second factor (or set of factors) is the business and financial risks of the Company in question. For example, the fact that a utility company effectively operates as a regulated monopoly, dedicated to providing an essential service (in this case gas retail delivery), typically would imply very low business risk and therefore a relatively low cost of equity. PSE&G's relatively strong balance sheet also contributes to its low cost of equity.

Q. DOES DR. MORIN INCORPORATE THESE PRINCIPLES?

A. In general, he attempts to incorporate these principles in conducting his DCF analysis. However, some of his non-DCF analyses do not adhere as closely to these principles. For example, risk premium studies make excessive use of historical or non-market data.

Q. WHAT METHODS ARE YOU USING IN THIS CASE?

A. I employ both the DCF and CAPM models, applied to a broad proxy group of gas distribution utility companies. However, for reasons discussed in my testimony, I emphasize the DCF model results in formulating my recommendation. It has been my experience that most utility regulatory commissions (federal and state) heavily emphasize the use of the DCF model to determine the cost of equity and setting the fair return. As a check (and partly to respond to Dr. Morin), I also perform a DCF study for a group of delivery service electric utilities as well as a series of CAPM calculations.

Q. PLEASE DESCRIBE THE DCF MODEL?

A. As mentioned, this model has been widely used in the regulatory community, including this Board. Its widespread acceptance is due to the fact that the model is market-based and is derived from standard economic/financial theory. The model is also transparent and understandable to regulators. I do not believe that an obscure or highly arcane model would receive the same degree of regulatory acceptance.

The theory begins by recognizing that any publicly-traded common stock (utility or otherwise) will sell at a price reflecting the discounted stream of cash flows <u>expected by investors</u>. The objective is to estimate that discount rate.

Using certain simplifying assumptions (that I believe are generally reasonable for utilities), the DCF model for dividend paying stocks can be distilled down as follows:

$Ke = (Do/Po)(1 + 0.5g) + g$, where:

Ke = cost of equity;

Do = the current annualized dividend;

Po = stock price at the current time; and

g = the long-term annualized dividend growth rate.

This is referred to as the constant growth DCF model, because for mathematical simplicity, it is assumed that the growth rate is constant for an indefinitely long time period. While this assumption may be unrealistic in many cases, for traditional utilities (which tend to be more stable than most unregulated companies) the assumption generally is reasonable, particularly when applied to a group of companies.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. Strictly speaking, the model can be applied only to publicly-traded companies, i.e., companies whose market prices (and therefore market valuations) are transparently revealed. Consequently, the model cannot be applied to PSE&G, which is a wholly-owned subsidiary of PSEG, and therefore, a market proxy is needed. In theory, PSEG could serve as that market proxy, but it would not be a very good one. PSEG has a very large investments in unregulated, relatively risky (compared to its delivery service utility operations) merchant generation assets. This does not resemble in any meaningful way the risk profile of the Company's gas delivery service operations.

In any case, I believe that an appropriately selected proxy group (preferably one reasonable in size) is likely to be more reliable than a single company study. This is because there is "noise" or fluctuations in stock price (or other) data that cannot always be readily accounted for in a simple DCF study. The use of an appropriate proxy group helps to allow such "data anomalies" to cancel out in the averaging process.

For the same reason, I prefer to use market data that is relatively current but averaged over a period of several months (i.e., six months rather than purely relying upon "spot" market data). It is important to recall that this is not an academic exercise but involves the setting of "permanent" utility rates that are likely to be in effect for several years. The practice of averaging market data over a period of several months can add stability to the results.

B. DCF Study Using the Proxy Group of Gas Distribution Utility Companies

Q. HOW DID YOU SELECT YOUR PROXY GROUP IN THIS CASE?

A. I am basing my primary DCF study on a large group of publicly-traded companies classified by the Value Line Investment Survey as gas distribution utility companies. These companies are in the same line of business as PSE&G's gas utility segment and therefore are a reasonable cost of equity proxy to be used in this case -- at least as a starting point. These fourteen proxy companies are listed on Schedule MIK-3, page 1 of 2, along with several risk indicators. The Value Line industry group includes a total of 17 companies, but I have removed three of these companies due to the fact that they do not pay dividends. It should be noted that although the companies are primarily regulated utilities, some also have some non-regulated operations that may be perceived as riskier (e.g., energy marketing). I make no specific adjustment to the DCF cost of capital results for those potentially riskier operations.

Q. HOW DOES THIS COMPARE TO THE PROXY GROUP OF GAS COMPANIES SELECTED BY DR. MORIN?

A. The two gas distribution proxy groups are nearly identical, with Dr. Morin selecting 13 of the 14 companies in my group. The one company in my group that Dr. Morin omits is Cascade Natural Gas Company. He may have omitted that company due to its smaller size as compared to the other gas companies. However, the decision to include it or exclude it has only a very minor effect on the DCF results. Cascade's Value Line beta is nearly identical to the group average and its dividend yield (a component of the DCF formula) modestly exceeds the group average. Hence, had I followed Dr. Morin and also omitted Cascade my DCF results would be a lower cost of equity, but the effect would be slight.

My conclusion is that the proxy group selection for gas utility proxy companies is not a significant issue in this case. I have a larger disagreement with Dr. Morin concerning the selection and appropriate role of electric utility proxy companies.

Q. HAVE EITHER YOU OR DR. MORIN PROPOSED A SPECIFIC RISK ADJUSTMENT TO THE COST OF EQUITY BETWEEN THE PROXY COMPANIES AND PSE&G'S GAS UTILITY OPERATIONS?

A. No. Although I have commented on the favorable risk attributes of PSE&G, neither of us has quantified or proposed a specific risk adjustment to the proxy group cost of equity results. Please note that the information shown on Schedule MIK-3, page 1 indicates that the capital structures of PSE&G and the proxy companies are very similar when short-term debt and current maturities of long-term debt are removed. However, when those two types of debt are included (and the credit rating agencies do include them), the proxy companies are more leveraged than PSE&G.

Q. HOW HAVE YOU APPLIED THE DCF MODEL TO THIS GROUP?

A. I have elected to use a six-month time period to measure the dividend yield component (Do/Po) of the DCF formula. Using the Standard & Poor's Stock Guide, I compiled the month-ending dividend yields for the six months ending April 2006, the most recent data available to me as of this writing. I anticipate updating to include May and June stock price data later in this proceeding, thereby providing a study based entirely on 2006 market data.

I show these dividend yield data on page 2 of Schedule MIK-4 for each proxy company, November 2005 through April 2006. Over this six-month period the group average dividend yields were highly stable ranging from a high of 4.28 percent in December to 4.07 percent in February, averaging 4.18 percent for the full six months. The April figures are nearly identical to the six-month average.

For DCF purposes and at this time, I am using a proxy group dividend yield of 4.18 percent.

Q. IS 4.18 PERCENT YOUR FINAL DIVIDEND YIELD?

A. Not quite. Strictly speaking, the dividend yield used in the model should be the value the investor expects over the next 12 months. Using the standard "half year" growth rate adjustment technique, the DCF adjusted yield becomes 4.3 percent. This is based on assuming that half of a year growth is 2.5 percent (i.e., a full year growth is 5.0 percent).

Q. DOES DR. MORIN EMPLOY THE SAME GROWTH RATE ADJUSTMENT?

A. No, he appears to use a full year of growth, which in my opinion is too large. A full year growth adjustment, strictly speaking, bases the dividend yield on the annualized level of the dividend one year from now, not the dividend over the course of the next 12 months. It appears that this inappropriately adds 0.1 percent to the cost of equity compared to using the more standard half year. This is a very small difference in results, and I do not believe there is a need to belabor the point, particularly given the fact that our DCF results are similar.

Q. HOW HAVE YOU DEVELOPED YOUR GROWTH RATE COMPONENT?

A. Unlike the dividend yield, the investor growth rate cannot be directly observed but instead must be inferred through a review of available evidence. The growth rate in question is the <u>long-run</u> dividend per share growth rate, but analysts frequently use earnings growth as a proxy for (long-term) dividend growth. This is because in the long-run earnings are the ultimate source of dividend payments to shareholders, and this is likely to be particularly true for a large group of companies.

One possible approach is to examine historical growth as a guide to investor expected future growth, for example the recent five-year or ten-year growth in earnings, dividends and book value per share. However, my experience with utilities has been in recent years is that these historic measures have been very volatile and are not reliable as prospective measures. This is due in part to extensive corporate restructuring. I note that Dr. Morin also chooses not to rely on historic growth measures for DCF purposes. The DCF growth rate should be prospective, and one useful source of information on prospective growth is the projections of earnings per share (typically five years) prepared by securities analysts. It appears that Dr. Morin places substantial if not exclusive weight on this information, and I agree that it warrants substantial emphasis.

Q. PLEASE DESCRIBE THIS EVIDENCE.

A. Schedule MIK-4, page 3 presents four well-known sources of projected earnings growth rates. Three of these four sources -- First Call, Zacks and Standard & Poors (S&P) -- provide averages from securities analyst surveys conducted by these organizations (typically the median value). The fourth, Value Line, is that organization's own estimates. Value Line publishes its own projections using annual earnings for a base period of 2002-2004 to a forecast period of 2009-2011.

As this schedule shows, the growth rates for individual companies vary somewhat among the four sources, but the growth averages are similar. These are 4.67 percent for S&P, 4.88 percent for First Call, 5.02 percent for Zacks and 5.21 percent for Value Line. The Value Line figures tend to be the most unstable of these four sources. In this case, I have selected the average of these four sources, or 5.07 percent, as the best measure of expected growth, and a range of 4.7 to 5.2 percent.

Q. IS THERE ANY OTHER EVIDENCE THAT SHOULD BE CONSIDERED?

A. Yes. There are a number of reasons why investor expectations of long-run growth could differ from the limited, five-year earnings projections from securities analysts. Consequently, while securities analyst estimates should be considered and given substantial weight, these growth rates should be subject to a reasonableness test and corroboration, to the extent feasible.

Schedule MIK-4, page 4 of 4, I have compiled three other measures of growth published by Value Line, i.e., growth rates of dividends and book value per share and long-run retained earnings growth. (Retained earnings growth reflects the growth over time one would expect from the reinvestment of retained earnings, i.e., earnings not paid out as dividends.) As shown on this Schedule, these growth measures tend to be similar to or less than analyst growth projections. Dividend growth averages 3.07 percent, book value growth averages 5.07 percent and earnings retention growth averages 4.82 percent. Two of the three measures fall within the 4.7 to 5.2 percent range of growth rates obtained from securities analysts earnings projections.

Q. WHAT IS YOUR DCF CONCLUSION?

A. I summarize my DCF analysis on page 1 of Schedule MIK-4. The adjusted dividend yield for the six months ending April 2006 is 4.3 percent for this group. Available evidence would support a long-run growth rate in the range of 4.7 to 5.2 percent, as explained above. Summing the adjusted yield and growth rates produces a total return of 9.0 percent 9.5 percent, and a midpoint result of 9.25 percent.

Q. HOW DOES YOUR DCF COST OF EQUITY COMPARE TO DR. MORIN'S GAS UTILITY DCF COST OF EQUITY?

A. Using a virtually identical proxy group, he obtains a cost of equity range of 9.0 to 9.9 percent. (Exhibits RAM-5 and 6, Column 5). This is slightly higher than my results and may be partly explained by the fact that Dr. Morin limited himself to just two sources of growth rate data. However, I generally regard his results as similar to mine.

Q. DO YOU INCLUDE AN ADJUSTMENT FOR FLOTATION EXPENSE?

A. A company can incur flotation expenses when engaging in a public issuance of common stock to support its growth in investment. It might choose to do so and incur this cost if retained earnings growth (or other capital sources such as dividend reinvestment programs) are insufficient. A public issuance typically involves significant underwriting fees, which the utility may seek to recover as a cost of equity adder. Dr. Morin includes 0.2 percent to his cost of equity estimate for that purpose.

I have seen no evidence that there are flotation expenses that PSE&G has incurred and should be recovered prospectively from its gas utility customers. Dr. Morin addresses flotation expense and its recovery generically for the proxy companies but presents no evidence that PSE&G (or its parent) has incurred these costs or will incur these costs for the foreseeable future. Available information, in fact, demonstrates that these costs have not been incurred in recent years and will not be incurred for the foreseeable future. Company management has stated that PSE&G can finance its capital needs with internally generated cash.[2] The response to RAR-ROR-14 states that PSEG has no plans for a public issuance of common equity (other than dividend reinvestments) through 2009. The response to RAR-ROR-7 indicates issuance costs were incurred in 2002 and 2003 related to common equity, but there is no indication that this pertains to gas utility operations as opposed to (for example) PSEG's unregulated operations.

In summary, there is no evidence of recent or prospective common stock issuance expenses attributable or caused by gas utility operations. Consequently, I do not believe that an equity return adjustment for flotation costs is appropriate or supported by the evidence.

Q. WHAT IS YOUR RECOMMENDATION AT THIS TIME?

[2] For example, see the Direct Testimony of Barry Mitchell (Exhibit JP-4) in the pending PSEG/Exelon merger proceeding (BPU Dkt. No. EM05020106, OAL Dkt. No. PUC 1874-05), page 5, ln. 6-7.

A. I am recommending the upper end of my 9.0 to 9.5 range, i.e., 9.5 percent. I am doing so for two reasons. First, there has been instability and arguably an upward trend in capital costs during the present calendar quarter as compared to earlier in 2006 (and late 2005). Second, other evidence such as the CAPM at least potentially could support a cost of capital result somewhat higher than my DCF range. However, I must reiterate my position that my DCF range for the proxy gas utility distribution group is far and away the best available evidence. Dr. Morin's own DCF analysis of the cost of equity supports my 9.5 percent result.

C. <u>Electric Utility DCF Cost of Equity</u>

Q. WHY ARE YOU CONDUCTING AN ELECTRIC UTILITY DCF STUDY?

A. A properly constructed electric utility study of the cost of equity, particularly one that focuses on the delivery service rather than generation sector, could provide a rough check on the gas distribution results. Moreover, Dr. Morin conducts an electric utility study, and it is therefore useful to present my own electric utility study for comparative purposes.

Q. WHAT COST OF EQUITY RESULTS DID DR. MORIN OBTAIN FOR HIS ELECTRIC UTILITIES?

A. Excluding his flotation adder, he obtains a range of 9.2 to 9.8 percent, again results roughly consistent with my recommendation of 9.5 percent and similar to his gas utility study results.

Q. HOW DID YOU PROCEED?

A. In this instance, I selected a proxy group of electric companies that have substantially (although not completely) divested their generation assets and operate mostly as delivery service electric utilities. I list these eight companies, along with certain risk indicators, on page 2 of Schedule MIK-3. While Dr. Morin does include most of these companies, his proxy group, he also includes a number of electrics with very substantial non-regulated generation assets (e.g., American Electric Power, FirstEnergy, Exelon, etc.), companies that may not be very similar to a gas utility company. This is why I have not included those "generation electrics."

Q. HOW HAVE YOU CONDUCTED YOUR DCF STUDY OF THESE DELIVERY SERVICE ELECTRICS?

A. I applied the DCF model in a very similar manner to my gas utility study, and this is shown on Schedule MIK-5. For these eight companies, I compile dividend yields for the six months ending April 2006, and this averages 4.80 percent. (See page 2 of Schedule MIK-2.) On page 3, I compile projected earnings growth rates from the same four sources used in my gas distribution study, and these average to 5.48 percent. As shown on page 4 of Schedule MIK-5, I compile the other three Value Line growth measures, which average to about 3 to 3.5 percent -- far lower than the projected earnings growth rates.

While I continue to place great weight (as does Dr. Morin) on projected earnings growth, there is one troubling problem with those data. One utility, UIL, which has traditionally been a very slow growing company, is shown as having extraordinarily rapid growth, as high as 18 percent annually. This is obviously not long-term growth but rather a recovery from a very weak base year. (That same source shows one-year growth of 29 percent followed by more "normal" growth of 5 percent thereafter.) If that one outlier is removed, the group average growth rate is a more realistic 4.83 percent. A more formal treatment of this problem is not to remove the outlier at all, but rather calculate the group median value (i.e., the midpoint of the range). The median growth rate for this proxy group (including all eight companies) is 4.57 percent.

Q. WHAT GROWTH RATE RANGE DID YOU SELECT?

A. I selected a range of 4.6 to 5.0 percent, which roughly comports with the median and adjusted mean. It is important to note that the Value Line measures on page 4 of this Schedule are well below this range, suggesting that these growth rates may be too high.

Q. WHAT IS YOUR DCF ESTIMATE FOR THIS GROUP?

A. As summarized on page 1 of Schedule MIK-5, the six-month average dividend yield is 4.8 percent, and adjusted forward it becomes 4.9 percent. Using a growth range of 4.6 to 5.0 percent, the DCF cost of equity becomes 9.5 to 9.9 percent.

These results are to be used only as a rough check on my primary gas utility study, and I have not reflected any risk differentials between these companies and PSE&G's gas service.

D. <u>The CAPM Analysis</u>

Q. PLEASE DESCRIBE THE CAPM MODEL.

A. The CAPM is a form of the "risk premium" approach and is based on modern portfolio theory. Based on my experience, the CAPM is the cost of equity method most often used in rate cases after the DCF method, and it is one of Dr. Morin's cost of equity methods.

According to this model, the cost of equity (Ke) is equal to the yield on a risk-free asset plus on equity risk premium multiplied by a firm's "beta" statistic. "Beta" is a firm-specific risk measure which is computed as the movements in a company's stock price (or market return) relative to contemporaneous movements in the broadly defined stock market. This measures the investment risk that cannot be reduced or eliminated through asset diversification (i.e., holding a broad portfolio of assets). The overall market, by definition, has a beta of 1.0, and a company with lower than average investment risk (e.g., a utility company) would have a beta below 1.0. The "risk premium" is defined as the expected return on the overall stock market minus the yield or return on a risk free asset.

The CAPM formula is:

$$K_e = R_f + \beta (R_m - R_f), \text{ where:}$$

K_e = the firm's cost of equity
R_m = the expected return on the overall market
R_f = the yield on the risk free asset
β = the firm (or group of firms) risk measure.

Two of the three principal variables in the model are directly observable -- the yield on a risk-free asset (e.g., a Treasury security yield) and the beta. For example, Value Line publishes estimated betas for each of the companies that it covers. The greatest difficulty, however, is in the measurement of the expected stock market return (and therefore the risk premium), since that variable cannot be directly observed.

While the beta itself also is "observable," different investor services provide differing estimates betas depending on the methods that they use. These differences can have large impacts on the CAPM results. In this case, both Dr. Morin and I use Value Line published betas, but I note that other sources have very different gas utility betas, which would yield lower results. For example, a reduction in the beta by 0.1 (e.g., from 0.80 to 0.70) would reduce the CAPM cost of equity by about 60 basis points.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. For purposes of my CAPM analysis, I have used a long-term (i.e., 20 year) Treasury yield as the risk free return and the average beta for the eleven proxy group companies. (See Schedule MIK-3, page 1 of 2, for the gas utility company-by-company betas.) In recent months, long-term Treasury yields have been approximately in the range of about 4.75 to 5.25 percent, and the Value Line beta for the proxy group averages 0.81. Finally, and as explained below, I am using a stock market return estimate of 10 to 12 percent, although I see less support for the upper end of that range.

Using these data inputs, the CAPM results are shown on page 1 of Schedule MIK-6. My low-end estimate uses a risk-free rate of 4.75 percent and a stock market return of 10.0 percent:

$$K_e = 4.75\% + 0.81\ (10.0 - 4.75) = 9.00\%$$

The upper end uses a risk-free rate of 5.25 percent and a stock market return of 12.0 percent.

$$Ke = 5.25 + 0.81\ (12.0 - 5.25) = 10.71\%$$

Thus, with these inputs the CAPM provides a return range of 9.00 to 10.71 percent, with a midpoint of 9.86 percent. The CAPM analysis produces results somewhat higher than the range of results from my DCF analysis, and I have factored this into the ROE recommendation in this case. However, the CAPM range of 9.0 to 10.7 percent brackets my 9.5 percent recommendation.

Q. IT APPEARS THAT A KEY ELEMENT IN YOUR CAPM STUDY IS YOUR MARKET RETURN RANGE OF 10 TO 12 PERCENT. HOW DID YOU DERIVE THAT RANGE?

A. Various measures of market return (and therefore the equity risk premium) are shown on page 3 of Schedule MIK-6. These market returns average to about 11.0 percent, and therefore the various equity risk premium measures average about 6.0 percent, if one assumes a prospective risk-free return of 5.0 percent.

Q. PLEASE DESCRIBE THESE MEASURES.

A. In general, two approaches have been used to obtain either the risk premium or the market return required by the CAPM. The first is to perform a DCF calculation on the overall stock market, and the second approach makes use of historical expected returns data measured over a long time period. Dr. Morin appears to make use of both methods, although I believe his estimates of the market return or risk premium are overstated.

Q. HAVE YOU PERFORMED A STOCK MARKET TOTAL RETURNS ANALYSIS?

A. Yes. Value Line publishes projections for its "Industrial Composite" twice each year, and that information can be used to perform a DCF total return calculation. The Industrial Composite is a broad measure of the overall stock market, excluding only utilities, financial services and non-North American companies. As of May 2006, Value Line was projecting five-year earnings growth of 8.0 percent and 2009 to 2011 growth from retained earnings of 12.0 percent. Combining the earnings growth rate with the reported dividend yield of 2.1 percent produces a total return of 10.1 percent. Using the average of projected earnings growth and future earnings retention growth (the two measures average to 10.0 percent), the DCF return becomes 12.1 percent. This suggests a DCF range for the Industrial Composite of about 10 to 12 percent.

In addition to Value Line, Zacks and First Call both published five-year estimates of the growth in earnings for the S&P 500 -- a broad measure of the stock market. (Recall that Zacks is Dr. Morin's preferred source of analyst growth rate projections.) Zacks currently is projecting 5-year earnings growth of 8.0 percent and First Call projects growth of 10.6 percent. Given the current S&P 500 dividend yield of 1.9 percent, this implies a total market return of about 9.9 to 12.5 percent. These results should be viewed with some caution since projected five-year growth may overstate expected long-term, sustainable growth. These various sources appear to support a stock market return range of about 10 to 12 percent, as shown on page 3 of Schedule MIK-6.

Q. WHAT ARE THE HISTORICAL RISK PREMIUM VALUES?

A. Cost of equity analysts frequently cite to historic returns data compiled by Ibbotson Associates, and I have used that source as well. Based on historic (1926-2003) after-the-fact returns published by the Ibbotson in 2004, the stock market risk premium relative to long-term Treasury bonds averages 6.6 percent. Combining that value with recent long-term Treasury yields of about 5.0 percent provides a market return of 11.6 percent. Dr. Morin also employs the long-term historical risk premium from Ibbotson but cites a somewhat higher figure, 7.2 percent.

There are reasons, however, for believing that even the 6.6 percent historical premium is too high. A recent research study by Ibbotson and Chen, estimates a long-term (arithmetic) historic risk premium of 5.9 percent. The authors estimate this figure using a supply-side model removing the effects of a rising P/E ratio over the historical period. This analysis acknowledges that the historical trend of rising P/Es served to inflate the achieved historical returns and such an increase would not be expected to continue indefinitely into the future. Combining the Ibbotson/Chen 5.9 percent risk premium with a current long-term Treasury yield of 5.0 percent produces an overall stock market return of 10.9 percent.[3] I would note that Ibbotson/Chen also report a geometric average risk premium of about 4 percent.

Q. PLEASE SUMMARIZE THE MARKET RETURN EVIDENCE.

A. These four measures of overall stock market return range from 9.9 to 12.5 percent, validating the assumed range used in my CAPM study on page 1 of Schedule MIK-6 of 10 to 12 percent. These stock market return estimates imply a (midpoint) stock market risk premium (relative to long-term Treasury bonds) of about 6 percent.

It should be noted that my CAPM study results in certain respects are conservatively high, even though my cost of equity estimate is significantly lower than those of Dr. Morin. While there may be a number of reasons why the CAPM estimates can differ, the calculation of beta sometimes is taken for granted. Dr. Morin and I both have used Value

[3] Roger G. Ibbotson and Peng Chen, "Stock Market Returns in the Long Run: Participating in the Real Economy," Financial Analyst Journal (forthcoming).

Line betas for the gas companies (0.81), but other sources provide lower estimates. On page 2 of Schedule MIK-6, I show the betas published by S&P and Yahoo Finance. Using two sources of these betas (or even averaging together the three sources) would significantly lower my 9.0 to 10.7 percent CAPM range. Controversies over beta, fisk premiums and estimates of stock market return are reasons for using the far more direct measure of the PSE&G cost of equity in this case -- the DCF method applied to gas distribution utilities.

V. <u>REPLY TO DR. MORIN</u>

A. Dr. Morin's Recommendation and Return Adequacy

Q. DR. MORIN RECOMMENDS A RETURN ON EQUITY IN THIS CASE OF 11.0 PERCENT. HOW DOES HE DEVELOP THIS RECOMMENDATION?

A. Dr. Morin cites three different types of cost of equity studies, DCF, CAPM and Risk Premium. (While the CAPM could be considered a type of Risk Premium study, for discussion purposes it is useful to make that distinction and separately identify it.) He presents 14 separate return estimates using these three types of studies, and he includes an adder of 0.2 percent for flotation expense. Dr. Morin states that his various study results "center around" 10.7 to 10.9 percent, and presumably excluding the 0.2 percent flotation adder they would "center around" 10.5 to 10.7 percent. He believes these results support a recommended return of 11.0 percent, based in part on de-emphasizing the DCF evidence. (Direct Testimony, page 55)

Dr. Morin's DCF evidence is approximately in the 9.0 to 9.9 percent range, and thus the midpoint of his range is generally consistent with my present recommendation of 9.5 percent. Thus, while I would not necessarily perform precisely the same DCF analysis as Dr. Morin, the differences between us in this case are modest. Thus, the key issue is not how the DCF studies are conducted, but rather what weight should be given to the DCF evidence. In my opinion, it should be given primary weight, and this is fully consistent with normal regulatory practice, whereas Dr. Morin seems to give it very little weight.

Q. WHAT IS THE BASIS FOR YOUR ASSERTION THAT DR. MORIN ASCRIBES LITTLE WEIGHT TO DCF EVIDENCE?

A. At page 54 of his testimony, Dr. Morin presents his 14 separate cost of equity calculations, four being CAPM, six being Risk Premium and four being DCF. Inclusive of the flotation adder, the four DCF studies yield 9.2 to 10.1 percent, or a midpoint of 9.65 percent. The remaining ten Risk Premium and CAPM calculations produce an average return on equity of 11.07 percent. These results make it clear that Dr. Morin essentially ignored his DCF results.

Q. DR. MORIN CRITICIZES THE DCF FOR UNDERSTATING RETURN IF MARKET PRICE EXCEEDS BOOK VALUE. IS THIS A VALID CRITICISM?

A. No, and it is notable that Dr. Morin cites no authority for this argument. The DCF is a financial modeling technique used to estimate the cost of equity, and the model is the same regardless as to whether the firm is a utility or a non-utility. The cost of equity is a market-derived price determined in unregulated capital markets by supply and demand forces, not by state regulators.

Dr. Morin's argument is not one of cost of equity estimation accuracy, but instead is one of fair compensation to utility investors. He believes the practice of using a book value rate base in connection with a market-based return does not provide investors with sufficient compensation if the stock price's market price exceeds book value. Nowhere does he claim that the DCF method fails to calculate the cost of equity, if properly applied. Rather, his dispute is with the basic concept of cost-based regulation, and whether it will end up "disappointing" investors.

Q. WHY DOES HE BELIEVE INVESTORS WILL BE DISAPPOINTED?

A. Let's suppose an accurate DCF yields an equity cost rate of 10 percent, and the equity portion of rate base is $1 billion. If exactly earned, the utility investors would receive $100 million per year. However, if the utility's market equity is $2 billion, this translates into only a 5 percent return on market value, and that is his complaint.

Q. WILL THIS DISAPOINT INVESTORS?

A. Obviously not. If Dr. Morin is correct, then the adoption and use of the DCF model (which has been widespread in the U. S.) would have disappointed utility investors for the last 20 years, causing utility stocks to plummet (thereby correcting the alleged market/book "problem"). This has not happened. Utility stocks in many, if not most, cases have exceeded book value for many years, while regulators have employed the DCF method, and the poor returns and disappointed investor problem claimed by Dr. Morin has not happened.

Q. HAS DR. MORIN PROPOSED AN ADJUSTMENT OR "FIX" TO THE DCF?

A. Other than heavily discounting it in his recommendation, he suggests no change to the DCF model to "correct" for this market/book premium problem.

Q. WOULD THIS ALLEDGED INVESTOR DISAPPOINTMENT PROBLEM OCCUR WITH THE CAPM AS WELL?

A. The issue is not DCF versus CAPM but rather setting the authorized return at the cost of equity. Assuming the CAPM model can accurately calculate the utility cost of equity, the same alleged "inadequate returns" problem would result if market price exceeded book value. This is because the criticism is really one of using the cost of equity to set a fair return on rate base.

Q. DR. MORIN INCLUDES AN ADJUSTMENT FOR FLOTATION COST. HOW MUCH DOES HE SEEK TO CHARGE CUSTOMERS FOR THIS ITEM?

A. PSE&G's common equity balance is approximately $3 billion, and I use that as a proxy for the combined electric, gas and transmission equity portion rate base. Dr. Morin's 20 basis point adder, inclusive of income tax effects, therefore would charge utility customers a total of about $10 million per year ($30 million over the next three years), even though PSEG (and PSE&G) expect to incur <u>no</u> flotation costs through 2009. There is also no evidence in this case that there are any unrecovered flotation expenses incurred in the past that are properly chargeable to PSE&G gas utility ratepayers.

B. Dr. Morin's Risk Premium Studies

Q. HOW HAS DR. MORIN ESTIMATED THE COST OF EQUITY USING THE RISK PREMIUM METHOD?

A. Dr. Morin employs two Risk Premium methods, the "Historical" returns method, which uses actual asset returns averaged over a lengthy time period, and "Allowed" returns method, which is based on a survey of state regulatory returns over a historical period. At the outset, I observe that the two methods appear to be contradictory. His Historical method calculates the average debt versus equity return over 1955 to 2001, and it uses this 47 year average value. The Allowed returns method argues that the risk premium is not constant and that an average premium for the historic period should not be used.

Q. IS DR. MORIN'S HISTORICAL RISK PREMIUM A VALID COST OF CAPITAL METHOD?

A. Keep in mind the purpose at hand is to determine as accurately as practicable the cost of equity at this time (in 2006) for PSE&G's gas distribution business. The Historic method is a mechanical exercise involving the calculation of after-the-fact realized returns on gas utility stocks and Treasury bonds during 1955 to 2001. At best, this method could provide a rough, ballpark estimate, but it is also possible (if not likely) that this method instead could be misleading. It is little more than a shot in the dark.

This method raises a number of questions that have no clear answers. The first is why the period 1955 to 2001 is the "correct" historical time period for measuring the risk premium that is valid today. Apparently, Dr. Morin did not "select" that period to obtain a specific result, but rather, he simply happened to have data available from that time period.

It turns out that the risk premium results are very sensitive to the time period selected. Using Dr. Morin's Exhibit RAM-3, I calculated the equity risk premium for the last 20 years of his period, i.e., from 1982 to 2001, and I obtain a value of 1.89 percent compared to his 47-year average of 5.66 percent. This means that the risk premium for 1955 to1981 (the first 27 years) is 8.45 percent. In other words, his study provides a risk premium of 8.45 percent for the first 27 years, 1.89 percent for the most recent 20 years and 5.66 percent for the full 47 years. Which one is right? Probably none, since the results appear to be arbitrary and the result of pure happenstance.

Even if one could calculate a meaningful risk premium from this historical time period, there is a serious question concerning whether it is meaningful today. At best, it reflects the risk and return circumstances for this historical period, and it may tell us little concerning PSE&G's equity return requirements today.

Q. HOW DID DR. MORIN MAKE USE OF ALLOWED RETURNS?

A. Dr. Morin reports the results from a survey of authorized rates of return during 1996 to 2005 compiled by Regulatory Research Associates, and for each year he calculates the difference between the average allowed return (per the survey) and yields on U. S. Treasury bonds. For example, if in a given year, the average allowed return is 10.0 percent and the Treasury yield that same year is 6 percent, then he would calculate the equity risk premium to be 4 percent (10.0% - 6.0%). For this entire ten-year historical period, he identifies an average risk premium averaging 5.4 percent.

Dr. Morin further claims that the risk premium changes over time, and therefore the average for this historical period should not be used. He instead applies a statistical regression analysis to these historical data, which has the effect of <u>increasing</u> the risk premium to be used in this case from 5.4 percent to as much as 6.2 percent. This is an obvious contradiction to his Historical risk premium study which relies directly on the 47 year historical average with no such modification. Moreover, Dr. Morin does not explain why one study uses 47 years of historical data and another uses <u>ten years</u>.

Q. DOES THIS METHOD MEASURE PSE&G'S CURRENT COST OF EQUITY FOR ITS GAS OPERATIONS?

A. No, and Dr. Morin does not directly state that this does. Rather, it seems to be largely just a comparison with returns that other commissions have granted gas utilities in the past, adjusted for changes over time in Treasury yields. Neither the state commissions nor the utilities are even identified by Dr. Morin, just aggregate annual results.

One might wish to make a leap and assume that the historic allowed returns are a reliable measure of the cost of equity during those years, and therefore this returns/equity premium data provide a useful cost of equity benchmark. His data series may indeed have something to do with the cost of equity, but the relationship can be very tenuous and ambiguous. State-allowed returns can reflect a great many factors including flotation adjustments, management performance premiums, implementation of multi-year rate plans, results from case settlements (where issues are traded off) and so forth. Moreover, rate case decision announced in a give year may be based on cost of capital data from the previous year due to rate case lags. Thus, while these data series may be interesting and reveal something about national regulatory trends, it is not a cost of equity method and is not market-based.

Q. IS DR. MORIN'S STATISTICAL MODEL THAT HE USES TO INCREASE THE RISK PREMIUM VALID?

A. No, I do not believe it is. His model is highly very simplified statistical test between the risk premium and Treasury yields, and it does show a correlation. However, Dr. Morin makes the classic mistake of assuming that <u>correlation</u> equates to <u>causation</u>. Statistical tests sometimes may reveal strong correlations that are nonsensical or spurious. Dr.

Morin has failed to provide any explanation concerning why such a correlation exists (if it exists), i.e., why changing Treasury yields <u>causes</u> the risk premium to change. In the end, his statistical exercise tells us nothing useful concerning PSE&G's gas utility cost of equity in 2006.

Q. ARE THERE ANY FURTHER STEPS DR. MORIN COULD TAKE?

A. Yes. If Dr. Morin wishes to rely on allowed returns as being relevant, why use allowed returns from unknown states and gas companies? Why not simply use the returns that have been allowed by the Board for PSE&G's most recent gas and electric retail cases in New Jersey, i.e., 10.0 percent and 9.75 percent, and adjust for the changes in Treasury yields since those cases. This would give him a result that is much more focused on PSE&G and New Jersey regulation than the method he uses.

C. <u>The CAPM Studies</u>

Q. WHAT ARE THE MAIN DIFFERENCES BETWEEN DR. MORIN'S CAPM ANALYSIS AND YOURS?

A. There are two main analytic differences. First, he claims that the stock market risk premium is 7.8 percentage points compared to my average estimate of about 6.0 percentage points, relative to long-term Treasury bond yields. I explained earlier why I believe that 6.0 percent is more realistic. Second, Dr. Morin introduces the "empirical" CAPM ("ECAPM") in addition to the standard version of the CAPM. This version calculates the cost of equity as the weighted average of the CAPM using the standard CAPM formula and a CAPM calculation that assumes the electric utility beta is 1.0 instead of its actual published value (about 0.80). The ECAPM adds about 0.4 percentage points to the cost of equity.

In addition to these two analytic issues, I employ the CAPM only as a check for comparative purposes, whereas for Dr. Morin it appears to play a central role in his recommendation.

Q. WHY DO YOU USE THE CAPM ONLY AS A CHECK?

A. The CAPM has generated much controversy in the financial literature, with Dr. Morin's ECAPM version being only one example. In addition, there is considerable disagreement among analysts over the magnitude of the stock market return or risk premium, with that disagreement producing a very wide range of cost of equity results. Dr. Morin cites certain high side estimates of that premium, but there are other literature estimates that are much lower, in fact, even lower than those I have used. Dr. Morin selectively ignores this evidence.[4] There can also be large differences in the calculation of the beta statistic, as I show on page 2 of Schedule MIK-6, which can have a large impact on the CAPM results. For these reasons, the CAPM has received far less acceptance from regulatory authorities than the DCF model for setting the utility cost of capital.

Q. HAS THE ECAPM RECEIVED SIGNIFICANT ACCEPTANCE FROM REGULATORS?

A. Dr. Morin has advocated this method for many years before state regulatory commissions, but it has received almost no acceptance.

Q. WHAT IS YOUR OBJECTION TO DR. MORIN'S ECAPM?

A. This ECAPM technique is mathematically equivalent to taking the beta published by Value Line and adjusting it <u>upward</u>, 25 percent of the way toward 1.0. There are several problems with this technique. First, since utility betas are almost always less than 1.0 (because investors perceive utilities to be less risky and therefore those stocks do not "move" as much as the market moves), the ECAPM will almost <u>always</u> produce a higher

[4] See Ibbotson and Peng (July 2002) for a discussion of other risk premium estimates from the literature, all of which are far lower than Dr. Morin's 7.8 percent.

utility cost of equity than the standard CAPM. While such a result is unpleasant, it is not necessarily wrong if utility betas are lower than 1.0 merely due to statistical "noise." But this is not the case. Utilities have low betas due to their underlying fundamentals (low business risk), and therefore there is no reason to "pretend" that utility betas are higher than their reported values.

Second, Dr. Morin overlooks the fact that when Value Line reports its betas it automatically includes a weighted average procedure that increases the beta toward 1.0 (or lowers it toward 1.0 if the "raw" beta is greater than 1.0). Hence, Dr. Morin's ECAPM weighting procedure is superfluous and amounts to "double dipping." I have already shown that Value Line betas are higher than betas from other sources.

Q. DOESN'T DR. MORIN PRESENT STATISTICAL EVIDENCE SUPPORTING THE NEED FOR THE ECAPM ADJUSTMENT?

A. Yes, but his supporting study is totally off point and unconvincing. (The study is included as Appendix A attached to his testimony). I previously reviewed the database used in his study and determine that this was a study entirely (or almost entirely) involving non-regulated companies. Thus, even if valid for non-utilities, it tells us nothing about the properties of beta and the CAPM for regulated utility companies.

Q. WHAT DO YOU CONCLUDE REGARDING THE ECAPM?

A. The ECAPM is a contrivance that artificially and systematically increases the CAPM estimate of the <u>utility</u> cost of equity. It has been widely disregarded by regulators and should be given no weight in this case.

Q. WHAT DO YOU CONCLUDE REGARDING THE USEFULNESS OF THE CAPM METHOD IN THIS PROCEEDING?

A. The CAPM has been highly controversial in the financial literature, and this proceeding should not seek to resolve that debate. Suffice it to say, the CAPM can be considered a legitimate cost of equity estimation method that has a place and use in regulatory proceedings. However, that use is a very limited one, and it should not be used as the central basis for setting PSE&G's return on equity. That task is far too important to customers to trust to so uncertain a method.

Based on today's Treasury yields, Dr. Morin claims that the CAPM produces returns in about the 11.5 to 12 percent range even though his gas utility DCF studies yield dramatically lower results -- well below 10 percent. My own CAPM, which is based on broader evidence, produces a very large range of uncertainty, 9.0 to 10.7 percent. Candidly, the true range of uncertainty is larger than that because I limited my calculations to Value Line betas when other sources of that parameter would produce different and lower CAPM estimates. Dr. Morin's CAPM studies have that same limitation.

The key observation is the following: Both Dr. Morin and I conduct gas utility DCF studies using slightly different techniques, data sets and time periods for the market data. Yet, our DCF studies are in basic agreement that the PSE&G gas utility cost of equity is in the 9 to 10 percent range. Our consensus on those findings argues powerfully for relying on the DCF evidence just as the Board has in the past.

The CAPM evidence has a much more limited role as a check and for identifying an appropriate point value cost of equity within the reasonable range of DCF evidence.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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APPENDIX A

QUALIFICATIONS OF

MATTHEW I. KAHAL

MATTHEW I. KAHAL

Mr. Kahal is currently an independent consulting economist, specializing in energy economics, public utility regulation and financial analysis. Over the past two decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing and a wide range of utility financial issues. In the financial area he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone and water utilities. Mr. Kahal's work in recent years has shifted to electric utility restructuring, mergers and competition.

Mr. Kahal has provided expert testimony on more than 250 occasions before state and federal regulatory commissions and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring and various other regulatory policy issues.

Education:

B.A. (Economics) - University of Maryland, 1971.

M.A. (Economics) - University of Maryland, 1974.

Ph.D. candidate - University of Maryland, completed all course work and qualifying examinations.

Previous Employment:

1981-2001 - Exeter Associates, Inc. (founding Principal).

1980-1981 - Member of the Economic Evaluation Directorate, The Aerospace Corporation, Washington, D.C. office.

1977-1980 - Economist, Washington, D.C. consulting firm.

1972-1977 - Research/Teaching Assistant and Instructor, Department of Economics, University of Maryland (College Park).

1975-1977 - Lecturer in Business/Economics, Montgomery College.

Professional Work Experience:

Mr. Kahal has more than twenty years experience managing and conducting consulting assignments relating to public utility economics and regulation. In 1981, he and five colleagues founded the firm of Exeter Associates, Inc. and for the next 20 years he served as a Principal and corporate officer in the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted both by Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring and utility purchase power contracts.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity he participated in a detailed financial assessment of the SPR, and developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of oil import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College teaching courses on economic principles, business and economic development.

Publications and Consulting Reports:

Projected Electric Power Demands of the Baltimore Gas and Electric Company, Maryland Power Plant Siting Program, 1979.

Projected Electric Power Demands of the Allegheny Power System, Maryland Power Plant Siting Program, January 1980.

An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula, Maryland Power Plant Siting Program, March 1980 (with Ralph E. Miller).

A Benefit/Cost Methodology of the Marginal Cost Pricing of Tennessee Valley Authority Electricity, prepared for the Board of Directors of the Tennessee Valley Authority, April 1980.

An Evaluation of the Delmarva Power and Light Company Generating Capacity Profile and Expansion Plan, (Interim Report), prepared for the Delaware Office of the Public Advocate, July 1980, (with Sharon L. Mason).

Rhode Island-DOE Electric Utilities Demonstration Project, Third Interim Report on Preliminary Analysis of the Experimental Results, prepared for the Economic Regulatory Administration, U.S. Department of Energy, July 1980.

Petroleum Inventories and the Strategic Petroleum Reserve, The Aerospace Corporation, prepared for the Strategic Petroleum Reserve Office, U.S. Department of Energy, December 1980.

Alternatives to Central Station Coal and Nuclear Power Generation, prepared for Argonne National Laboratory and the Office of Utility Systems, U.S. Department of Energy, August 1981.

"An Econometric Methodology for Forecasting Power Demands," Conducting Need-for-Power Review for Nuclear Power Plants (D.A. Nash, ed.), U.S. Nuclear Regulatory Commission, NUREG-0942, December 1982.

State Regulatory Attitudes Toward Fuel Expense Issues, prepared for the Electric Power Research Institute, July 1983, (with Dale E. Swan).

"Problems in the Use of Econometric Methods in Load Forecasting," Adjusting to Regulatory, Pricing and Marketing Realities (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1983.

Proceedings of the Maryland Conference on Electric Load Forecasting, (editor and contributing author), Maryland Power Plant Siting Program, PPES-83-4, October 1983.

"The Impacts of Utility-Sponsored Weatherization Programs: The Case of Maryland Utilities," (with others), in Government and Energy Policy (Richard L. Itteilag, ed.), 1983.

Power Plant Cumulative Environmental Impact Report, contributing author, (Paul E. Miller, ed.) Maryland Department of Natural Resources, January 1984.

Projected Electric Power Demands for the Potomac Electric Power Company, three volumes with Steven L. Estomin), prepared for the Maryland Power Plant Siting Program, March 1984.

"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting," (with Thomas Bacon, Jr. and Steven L. Estomin), published in the Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, 1984.

"Nuclear Power and Investor Perceptions of Risk," (with Ralph E. Miller), published in The Energy Industries in Transition: 1985-2000 (John P. Weyant and Dorothy Sheffield, eds.), 1984.

The Financial Impact of Potential Department of Energy Rate Recommendations on the Commonwealth Edison Company, prepared for the U.S. Department of Energy, October 1984.

"Discussion Comments," published in Impact of Deregulation and Market Forces on Public Utilities: The Future of Regulation (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1985.

An Econometric Forecast of the Electric Power Loads of Baltimore Gas and Electric Company, two volumes (with others), prepared for the Maryland Power Plant Siting Program, 1985.

A Survey and Evaluation of Demand Forecast Methods in the Gas Utility Industry, prepared for the Public Utilities Commission of Ohio, Forecasting Division, November 1985, (with Terence Manuel).

A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company -- Past and Present, prepared for the Texas Public Utility Commission, December 1985, (with Marvin H. Kahn).

Power Plant Cumulative Environmental Impact Report for Maryland, principal author of three of the eight chapters in the report (Paul E. Miller, ed.), PPSP-CEIR-5, March 1986.

"Potential Emissions Reduction from Conservation, Load Management, and Alternative Power," published in Acid Deposition in Maryland: A Report to the Governor and General Assembly, Maryland Power Plant Research Program, AD-87-1, January 1987.

Determination of Retrofit Costs at the Oyster Creek Nuclear Generating Station, March 1988, prepared for Versar, Inc., New Jersey Department of Environmental Protection.

Excess Deferred Taxes and the Telephone Utility Industry, April 1988, prepared on behalf of the National Association of State Utility Consumer Advocates.

Toward a Proposed Federal Policy for Independent Power Producers, comments prepared on behalf of the Indiana Consumer Counselor, FERC Docket EL87-67-000, November 1987.

Review and Discussion of Regulations Governing Bidding Programs, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

A Review of the Proposed Revisions to the FERC Administrative Rules on Avoided Costs and Related Issues, prepared for the Pennsylvania Office of Consumer Advocate, April 1988.

Review and Comments on the FERC NOPR Concerning Independent Power Producers, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

The Costs to Maryland Utilities and Ratepayers of an Acid Rain Control Strategy -- An Updated Analysis, prepared for the Maryland Power Plant Research Program, October 1987, AD-88-4.

"Comments," in New Regulatory and Management Strategies in a Changing Market Environment (Harry M. Trebing and Patrick C. Mann, editors), Proceedings of the Institute of Public Utilities Eighteenth Annual Conference, 1987.

Electric Power Resource Planning for the Potomac Electric Power Company, prepared for the Maryland Power Plant Research Program, July 1988.

Power Plant Cumulative Environmental Impact Report for Maryland (Thomas E. Magette, ed.) authored two chapters, November 1988, PPRP-CEIR-6.

Resource Planning and Competitive Bidding for Delmarva Power & Light Company, October 1990, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

Electric Power Rate Increases and the Cleveland Area Economy, prepared for the Northeast Ohio Areawide Coordinating Agency, October 1988.

An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum)

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

An Economic Perspective on Competition and the Electric Utility Industry, November 1994. Prepared for the Electric Consumers' Alliance.

PEPCO's Clean Air Act Compliance Plan: Status Report, prepared for the Maryland Power Plant Research Plan, January 1995 (w/Diane Mountain, Environmental Resources Management, Inc.).

The FERC Open Access Rulemaking: A Review of the Issues, prepared for the Indiana Office of Utility Consumer Counselor and the Pennsylvania Office of Consumer Advocate, June 1995.

A Status Report on Electric Utility Restructuring: Issues for Maryland, prepared for the Maryland Power Plant Research Program, November 1995 (with Daphne Psacharopoulos).

Modeling the Financial Impacts on the Bell Regional Holding Companies from Changes in Access Rates, prepared for MCI Corporation, May 1996.

The CSEF Electric Deregulation Study: Economic Miracle or the Economists' Cold Fusion?, prepared for the Electric Consumers' Alliance, Indianapolis, Indiana, October 1996.

Reducing Rates for Interstate Access Service: Financial Impacts on the Bell Regional Holding Companies, prepared for MCI Corporation, May 1997.

The New Hampshire Retail Competition Pilot Program: A Preliminary Evaluation, July 1997, prepared for the Electric Consumers' Alliance (with Jerome D. Mierzwa).

Electric Restructuring and the Environment: Issue Identification for Maryland, March 1997, prepared for the Maryland Power Plant Research Program (with Environmental Resource Management, Inc.)

An Analysis of Electric Utility Embedded Power Supply Costs, prepared for Power-Gen International Conference, Dallas, Texas, December 1997.

Market Power Outlook for Generation Supply in Louisiana, December 2000, prepared for the Louisiana Public Service Commission (with others).

A Review of Issues Concerning Electric Power Capacity Markets, prepared for the Maryland Power Plant Research Program, December 2001 (with B. Hobbs and J. Inon).

The Economic Feasibility of Air Emissions Controls at the Brandon Shores and Morgantown Coal-fired Power Plants, February 2005, (prepared for the Chesapeake By Foundation).

The Economic Feasibility of Power Plant Retirements on the Entergy System, September 2005 with Phil Hayet (prepared for the Louisiana Public Service Commission).

Conference and Workshop Presentations:

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995, (presentation concerning the FERC rulemaking on electric transmission open access).

The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on "Restructuring the Electric Industry," sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Power-Gen '97 International Conference, Dallas, Texas, December 1997 (presentation concerning utility embedded costs of generation supply).

Consumer Summit on Electric Competition, sponsored by the National Consumers League and Electric Consumers' Alliance, Washington, D.C., March 2001 (presentation concerning generation supply and reliability).

National Association of State Utility Consumer Advocates, Mid-Year Meetings, Austin, Texas, June 16-17, 2002 (presenter and panelist on RTO/Standard Market Design issues).

Louisiana State Bar Association, Public Utility Section, October 2, 2002. (Presentation on Performance-Based Ratemaking and panelist on RTO issues). Baton Rouge, Louisiana.

Virginia State Corporation Commission/Virginia State Bar, Twenty Second National Regulatory Conference, May 10, 2004. (Presentation on Electric Transmission System Planning.) Williamsburg, Virginia.

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
1.	27374 & 27375 October 1978	Long Island Lighting Company	New York Counties	Nassau & Suffolk	Economic impacts of proposed rate increase
2.	6807 January 1978	Generic	Maryland	MD Power Plant Siting Program	Load forecasting
3.	78-676-EL-AIR February 1978	Ohio Power Company	Ohio	Ohio Consumers' Counsel	Test year sales and revenues
4.	17667 May 1979	Alabama Power Company	Alabama	Attorney General	Test year sales, revenues, costs and load forecasts
5.	None April 1980	Tennessee Valley Authority	TVA Board	League of Women Voters	Time-of-use pricing
6.	R-80021082	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Load forecasting, marginal cost pricing
7.	7259 (Phase I) October 1980	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load forecasting
8.	7222 December 1980	Delmarva Power & Light Company	Maryland	MD Power Plant Siting Program	Need for plant, load forecasting
9.	7441 June 1981	Potomac Electric Power Company	Maryland	Commission Staff	PURPA standards
10.	7159 May 1980	Baltimore Gas & Electric	Maryland	Commission Staff	Time-of-use pricing
11.	81-044-E-42T	Monongahela Power	West Virginia	Commission Staff	Time-of-use rates
12.	7259 (Phase II) November 1981	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load forecasting, load management
13.	1606 September 1981	Blackstone Valley Electric and Narragansett	Rhode Island	Division of Public Utilities	PURPA standards
14.	RID 1819 April 1982	Pennsylvania Bell	Pennsylvania	Office of Consumer Advocate	Rate of return
15.	82-0152 July 1982	Illinois Power Company	Illinois	U.S. Department of Defense	Rate of return, CWIP
16.	7559 September 1982	Potomac Edison Company	Maryland	Commission Staff	Cogeneration
17.	820150-EU September 1982	Gulf Power Company	Florida	Federal Executive Agencies	Rate of return, CWIP
18.	82-057-15 January 1983	Mountain Fuel Supply Company	Utah	Federal Executive Agencies	Rate of return, capital structure

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
19.	5200 August 1983	Texas Electric Service Company	Texas	Federal Executive Agencies	Cost of equity
20.	28069 August 1983	Oklahoma Natural Gas	Oklahoma	Federal Executive Agencies	Rate of return, deferred taxes, capital structure, attrition
21.	83-0537 February 1984	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of return, capital structure, financial capability
22.	84-035-01 June 1984	Utah Power & Light Company	Utah	Federal Executive Agencies	Rate of return
23.	U-1009-137 July 1984	Utah Power & Light Company	Idaho	U.S. Department of Energy	Rate of return, financial condition
24.	R-842590 August 1984	Philadelphia Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of return
25.	840086-EI August 1984	Gulf Power Company	Florida	Federal Executive Agencies	Rate of return, CWIP
26.	84-122-E August 1984	Carolina Power & Light Company	South Carolina	South Carolina Consumer Advocate	Rate of return, CWIP, load forecasting
27.	CGC-83-G & CGC-84-G October 1984	Columbia Gas of Ohio	Ohio	Ohio Division of Energy	Load forecasting
28.	R-842621 October 1984	Western Pennsylvania Water Company	Pennsylvania	Office of Consumer Advocate	Test year sales
29.	R-842710 January 1985	ALLTEL Pennsylvania Inc.	Pennsylvania	Office of Consumer Advocate	Rate of return
30.	ER-504 February 1985	Allegheny Generating Company	FERC	Office of Consumer Advocate	Rate of return
31.	R-842632 March 1985	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of return, conservation, time-of-use rates
32.	83-0537 & 84-0555 April 1985	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of return, incentive rates, rate base
33.	Rulemaking Docket No. 11, May 1985	Generic	Delaware	Delaware Commission Staff	Interest rates on refunds
34.	29450 July 1985	Oklahoma Gas & Electric Company	Oklahoma	Oklahoma Attorney General	Rate of return, CWIP in rate base
35.	1811 August 1985	Bristol County Water Company	Rhode Island	Division of Public Utilities	Rate of return, capital structure

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
36.	R-850044 & R-850045 August 1985	Quaker State & Continental Telephone Companies	Pennsylvania	Office of Consumer Advocate	Rate of return
37.	R-850174 November 1985	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return, financial conditions
38.	U-1006-265 March 1986	Idaho Power Company	Idaho	U.S. Department of Energy	Power supply costs and models
39.	EL-86-37 & EL-86-38 September 1986	Allegheny Generating Company	FERC	PA Office of Consumer Advocate	Rate of return
40.	R-850287 June 1986	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of return
41.	1849 August 1986	Blackstone Valley Electric	Rhode Island	Division of Public Utilities	Rate of return, financial condition
42.	86-297-GA-AIR November 1986	East Ohio Gas Company	Ohio	Ohio Consumers' Counsel	Rate of return
43.	U-16945 December 1986	Louisiana Power & Light Company	Louisiana	Public Service Commission	Rate of return, rate phase-in plan
44.	Case No. 7972 February 1987	Potomac Electric Power Company	Maryland	Commission Staff	Generation capacity planning, purchased power contract
45.	EL-86-58 & EL-86-59 March 1987	System Energy Resources and Middle South Services	FERC	Louisiana PSC	Rate of return
46.	ER-87-72-001 April 1987	Orange & Rockland	FERC	PA Office of Consumer Advocate	Rate of return
47.	U-16945 April 1987	Louisiana Power & Light Company	Louisiana	Commission Staff	Revenue requirement update phase-in plan
48.	P-870196 May 1987	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contract
49.	86-2025-EL-AIR June 1987	Cleveland Electric Illuminating Company	Ohio	Ohio Consumers' Counsel	Rate of return
50.	86-2026-EL-AIR June 1987	Toledo Edison Company	Ohio	Ohio Consumers' Counsel	Rate of return
51.	87-4 June 1987	Delmarva Power & Light Company	Delaware	Commission Staff	Cogeneration/small power

	Docket Number	Utility	Jurisdiction	Client	Subject
52.	1872 July 1987	Newport Electric Company	Rhode Island	Commission Staff	Rate of return
53.	WO 8606654 July 1987	Atlantic City Sewerage Company	New Jersey	Resorts International	Financial condition
54.	7510 August 1987	West Texas Utilities Company	Texas	Federal Executive Agencies	Rate of return, phase-in
55.	8063 Phase I October 1987	Potomac Electric Power Company	Maryland	Power Plant Research Program	Economics of power plant site selection
56.	00439 November 1987	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Cogeneration economics
57.	RP-87-103 February 1988	Panhandle Eastern Pipe Line Company	FERC	Indiana Utility Consumer Counselor	Rate of return
58.	EC-88-2-000 February 1988	Utah Power & Light Co. PacifiCorp	FERC	Nucor Steel	Merger economics
59.	87-0427 February 1988	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Financial projections
60.	870840 February 1988	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return
61.	870832 March 1988	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of return
62.	8063 Phase II July 1988	Potomac Electric Power Company	Maryland	Power Plant Research Program	Power supply study
63.	8102 July 1988	Southern Maryland Electric Cooperative	Maryland	Power Plant Research Program	Power supply study
64.	10105 August 1988	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of return, incentive regulation
65.	00345 August 1988	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Need for power
66.	U-17906 September 1988	Louisiana Power & Light Company	Louisiana	Commission Staff	Rate of return, nuclear power costs Industrial contracts
67.	88-170-EL-AIR October 1988	Cleveland Electric Illuminating Co.	Ohio	Northeast-Ohio Areawide Coordinating Agency	Economic impact study

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
68.	1914 December 1988	Providence Gas Company	Rhode Island	Commission Staff	Rate of return
69.	U-12636 & U-17649 February 1989	Louisiana Power & Light Company	Louisiana	Commission Staff	Disposition of litigation proceeds
70.	00345 February 1989	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Load forecasting
71.	RP88-209 March 1989	Natural Gas Pipeline of America	FERC	Indiana Utility Consumer Counselor	Rate of return
72.	8425 March 1989	Houston Lighting & Power Company	Texas	U.S. Department of Energy	Rate of return
73.	EL89-30-000 April 1989	Central Illinois Public Service Company	FERC	Soyland Power Coop, Inc.	Rate of return
74.	R-891208 May 1989	Pennsylvania American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return
75.	89-0033 May 1989	Illinois Bell Telephone Company	Illinois	Citizens Utility Board	Rate of return
76.	881167-EI May 1989	Gulf Power Company	Florida	Federal Executive Agencies	Rate of return
77.	R-891218 July 1989	National Fuel Gas Distribution Company	Pennsylvania	Office of Consumer Advocate	Sales forecasting
78.	8063, Phase III Sept. 1989	Potomac Electric Power Company	Maryland	Depart. Natural Resources	Emissions Controls
79.	37414-S2 October 1989	Public Service Company of Indiana	Indiana	Utility Consumer Counselor	Rate of return, DSM, off-system sales, incentive regulation
80.	October 1989	Generic	U.S. House of Reps. Comm. on Ways & Means	NA	Excess deferred income tax
81.	38728 November 1989	Indiana Michigan Power Company	Indiana	Utility Consumer Counselor	Rate of return
82.	RP89-49-000 December 1989	National Fuel Gas Supply Corporation	FERC	PA Office of Consumer Advocate	Rate of return
83.	R-891364 December 1989	Philadelphia Electric Company	Pennsylvania	PA Office of Consumer Advocate	Financial impacts (surrebuttal only)
84.	RP89-160-000 January 1990	Trunkline Gas Company	FERC	Indiana Utility Consumer Counselor	Rate of return

	Docket Number	Utility	Jurisdiction	Client	Subject
85.	EL90-16-000 November 1990	System Energy Resources, Inc.	FERC	Louisiana Public Service Commission	Rate of return
86.	89-624 March 1990	Bell Atlantic	FCC	PA Office of Consumer Advocate	Rate of return
87.	8245 March 1990	Potomac Edison Company	Maryland	Depart. Natural Resources	Avoided Cost
88.	000586 March 1990	Public Service Company of Oklahoma	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
89.	38868 March 1990	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of return
90.	1946 March 1990	Blackstone Valley Electric Company	Rhode Island	Division of Public Utilities	Rate of return
91.	000776 April 1990	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
92.	890366 May 1990, December 1990	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Competitive Bidding Program Avoided Costs
93.	EC-90-10-000 May 1990	Northeast Utilities	FERC	Maine PUC, et. al.	Merger, Market Power, Transmission Access
94.	ER-891109125 July 1990	Jersey Central Power & Light	New Jersey	Rate Counsel	Rate of return
95.	R-901670 July 1990	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of return Test year sales
96.	8201 October 1990	Delmarva Power & Light Company	Maryland	Depart. Natural Resources	Competitive Bidding, Resource Planning
97.	EL90-45-000 April 1991	Entergy Services, Inc.	FERC	Louisiana PSC	Rate of return
98.	GR90080786J January 1991	New Jersey Natural Gas	New Jersey	Rate Counsel	Rate of return
99.	90-256 January 1991	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of return
100.	U-17949A February 1991	South Central Bell Telephone Co.	Louisiana	Louisiana PSC	Rate of return
101.	ER90091090J April 1991	Atlantic City Electric Company	New Jersey	Rate Counsel	Rate of return

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	Docket Number	Utility	Jurisdiction	Client	Subject
102.	8241, Phase I April 1991	Baltimore Gas & Electric Co.	Maryland	Dept. of Natural Resources	Environmental controls
103.	8241, Phase II May 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Need for Power, Resource Planning
104.	39128 May 1991	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of return, rate base, financial planning
105.	P-900485 May 1991	Duquesne Light Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
106.	G900240 P910502 May 1991	Metropolitan Edison Co. Pennsylvania Electric Co.	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
107.	GR901213915 May 1991	Elizabethtown Gas Co.	New Jersey	Rate Counsel	Rate of return
108.	91-5032 August 1991	Nevada Power Co.	Nevada	U.S. Dept. of Energy	Rate of return
109.	EL90-48-000 November 1991	Entergy Services	FERC	Louisiana PSC	Capacity transfer
110.	000662 September 1991	Southwestern Bell Telephone	Oklahoma	Attorney General	Rate of return
111.	U-19236 October 1991	Arkansas Louisiana Gas Company	Louisiana	Louisiana PSC Staff	Rate of return
112.	U-19237 December 1991	Louisiana Gas Service Company	Louisiana	Louisiana PSC Staff	Rate of return
113.	ER91030356J October 1991	Rockland Electric Company	New Jersey	Rate Counsel	Rate of return
114.	GR91071243J February 1992	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of return
115.	GR91081393J March 1992	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Rate of return
116.	P-870235 et al. March 1992	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contracts
117.	8413 March 1992	Potomac Electric Power Company	Maryland	Dept. of Natural Resources	IPP purchased power contracts
118.	39236 March 1992	Indianapolis Power & Light Company	Indiana	Utility Consumer Counselor	Least-cost planning Need for power

	Docket Number	Utility	Jurisdiction	Client	Subject
119.	R-912164 April 1992	Equitable Gas Company	Pennsylvania	Office of Consumer Advocate	Rate of return
120.	ER-91111698J May 1992	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Rate of return
121.	U-19631 June 1992	Trans Louisiana Gas Company	Louisiana	PSC Staff	Rate of return
122.	ER-91121820J July 1992	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Rate of return
123.	R-00922314 August 1992	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Rate of return
124.	92-049-05 September 1992	US West Communications	Utah	Committee of Consumer Services	Rate of return
125.	92PUE0037 September 1992	Commonwealth Gas Company	Virginia	Attorney General	Rate of return
126.	EC92-21-000 September 1992	Entergy Services, Inc.	FERC	Louisiana PSC	Merger Impacts (Affidavit)
127.	ER92-341-000 December 1992	System Energy Resources	FERC	Louisiana PSC	Rate of return
128.	U-19904 November 1992	Louisiana Power & Light Company	Louisiana	Staff	Merger analysis, competition competition issues
129.	8473 November 1992	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	QF contract evaluation
130.	IPC-E-92-25 January 1993	Idaho Power Company	Idaho	Federal Executive Agencies	Power supply clause
131.	E002/GR-92-1185 February 1993	Northern States Power Company	Minnesota	Attorney General	Rate of return
132.	92-102, Phase II March 1992	Central Maine Power Company	Maine	Staff	QF contracts prudence and procurements practices
133.	EC92-21-000 March 1993	Entergy Corporation	FERC	Louisiana PSC	Merger issues
134.	8489 March 1993	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	Power plant certification
135.	11735 April 1993	Texas Electric Utilities Company	Texas	Federal Executives Agencies	Rate of return

	Docket Number	Utility	Jurisdiction	Client	Subject
136.	2082 May 1993	Providence Gas Company	Rhode Island	Division of Public Utilities	Rate of return
137.	P-00930715 December 1993	Bell Telephone Co. of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of return, financial projections, Bell/TCI merger
138.	R-00932670 February 1994	Pennsylvania-American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return
139.	8583 February 1994	Conowingo Power Co.	Maryland	Dept. of Natural Resources	Competitive bidding for power supplies
140.	E-015/GR-94-001 April 1994	Minnesota Power & Light Co.	Minnesota	Attorney General	Rate of return
141.	CC Docket No. 94-1 May 1994	Generic Telephone	FCC	MCI Comm. Corp.	Rate of return
142.	92-345, Phase II June 1994	Central Maine Power Co.	Maine	Advocacy Staff	Price Cap Regulation Fuel Costs
143.	93-11065 April 1994	Nevada Power Co.	Nevada	Federal Executive Agencies	Rate of return
144.	94-0065 May 1994	Commonwealth Edison Co.	Illinois	Federal Executive Agencies	Rate of return
145.	GR94010002J June 1994	South Jersey Gas Co.	New Jersey	Rate Counsel	Rate of return
146.	WR94030059 July 1994	New Jersey-American Water Co.	New Jersey	Rate Counsel	Rate of return
147.	RP91-203-000 June 1994	Tennessee Gas Pipeline Company	FERC	Customer Group	Environmental Externalities (oral testimony only)
148.	ER94-998-000 July 1994	Ocean State Power	FERC	Boston Edison Co.	Rate of return
149.	R-00942986 July 1994	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Rate of return, emission allowances
150.	94-121 August 1994	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of return
151.	35854-S2 November 1994	PSI Energy, Inc.	Indiana	Utility Consumer Counsel	Merger savings and allocations
152.	IPC-E-94-5 November 1994	Idaho Power Co.	Idaho	Federal Executive Agencies	Rate of return

	Docket Number	Utility	Jurisdiction	Client	Subject
153.	November 1994	Edmonton Water	Alberta, Canada	Regional Customer Group	Rate of return (rebuttal only)
154.	90-256 December 1994	South Central Bell Telephone Co.	Kentucky	Attorney General	Incentive Plan True-Ups
155.	U-20925 February 1995	Louisiana Power & Light Company	Louisiana	PSC Staff	Rate of return Industrial contracts Trust fund earnings
156.	R-00943231 February 1995	Pennsylvania-American Water Company	Pennsylvania	Consumer Advocate	Rate of return
157.	8678 March 1995	Generic	Maryland	Dept. Natural Resources	Electric Competition Incentive Regulation (oral only)
158.	R-000943271 April 1995	Pennsylvania Power & Light Company	Pennsylvania	Consumer Advocate	Rate of return Nuclear decommissioning Capacity Issues
159.	U-20925 May 1995	Louisiana Power & Light Company	Louisiana	Commission Staff	Class cost of service issues
160.	2290 June 1995	Narragansett Electric Company	Rhode Island	Division Staff	Rate of return
161.	U-17949E June 1995	South Central Bell Telephone Company	Louisiana	Commission Staff	Rate of return
162.	2304 July 1995	Providence Water Supply Board	Rhode Island	Division Staff	Cost recovery of capital spending program
163.	ER95-625-000 et al. August 1995	PSI Energy, Inc.	FERC	Office of Utility Consumer Counselor	Rate of return
164.	P-00950915 et al. September 1995	Paxton Creek Cogeneration Assoc.	Pennsylvania	Office of Consumer Advocate	Cogeneration contract amendment
165.	8702 September 1995	Potomac Edison Company	Maryland	Dept. of Natural Resources	Allocation of DSM Costs (oral only)
166.	ER95-533-001 September 1995	Ocean State Power	FERC	Boston Edison Co.	Cost of equity
167.	40003 November 1995	PSI Energy, Inc.	Indiana	Utility Consumer Counselor	Rate of return Retail wheeling
168.	P-55, SUB 1013 January 1996	BellSouth	North Carolina	AT&T	Rate of return

	Docket Number	Utility	Jurisdiction	Client	Subject
169.	P-7, SUB 825 January 1996	Carolina Tel.	North Carolina	AT&T	Rate of return
170.	February 1996	Generic Telephone	FCC	MCI	Cost of capital
171.	95A-531EG April 1996	Public Service Company of Colorado	Colorado	Federal Executive Agencies	Merger issues
172.	ER96-399-000 May 1996	Northern Indiana Public Service Company	FERC	Indiana Office of Utility Consumer Counselor	Cost of capital
173.	8716 June 1996	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	DSM programs
174.	8725 July 1996	BGE/PEPCO	Maryland	Md. Energy Admin.	Merger Issues
175.	U-20925 August 1996	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of return Allocations Fuel Clause
176.	EC96-10-000 September 1996	BGE/PEPCO	FERC	Md. Energy Admin.	Merger issues competition
177.	EL95-53-000 November 1996	Entergy Services, Inc.	FERC	Louisiana PSC	Nuclear Decommissioning
178.	WR96100768 March 1997	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Cost of Capital
179.	WR96110818 April 1997	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Cost of Capital
180.	U-11366 April 1997	Ameritech Michigan	Michigan	MCI	Access charge reform/financial condition
181.	97-074 May 1997	BellSouth	Kentucky	MCI	Rate Rebalancing financial condition
182.	2540 June 1997	New England Power	Rhode Island	PUC Staff	Divestiture Plan
183.	96-336-TP-CSS June 1997	Ameritech Ohio	Ohio	MCI	Access Charge reform Economic impacts
184.	WR97010052 July 1997	Maxim Sewerage Corp.	New Jersey	Ratepayer Advocate	Rate of Return
185.	97-300 August 1997	LG&E/KU	Kentucky	Attorney General	Merger Plan

	Docket Number	Utility	Jurisdiction	Client	Subject
186.	Case No. 8738 August 1997	Generic (oral testimony only)	Maryland	Dept. of Natural Resources	Electric Restructuring Policy
187.	Docket No. 2592 September 1997	Eastern Utilities	Rhode Island	PUC Staff	Generation Divestiture
188.	Case No.97-247 September 1997	Cincinnati Bell Telephone	Kentucky	MCI	Financial Condition
189.	Docket No. U-20925 November 1997	Entergy Louisiana	Louisiana	PSC Staff	Rate of Return
190.	Docket No. D97.7.90 November 1997	Montana Power Co.	Montana	Montana Consumers Counsel	Stranded Cost
191.	Docket No. EO97070459 November 1997	Jersey Central Power & Light Co.	New Jersey	Ratepayer Advocate	Stranded Cost
192.	Docket No. R-00974104 November 1997	Duquesne Light Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
193.	Docket No. R-00973981 November 1997	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
194.	Docket No. A-1101150F0015 November 1997	Allegheny Power System DQE, Inc.	Pennsylvania	Office of Consumer Advocate	Merger Issues
195.	Docket No. WR97080615 January 1998	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Rate of Return
196.	Docket No. R-00974149 January 1998	Pennsylvania Power Company	Pennsylvania	Office of Consumer Advocate	Stranded Cost
197.	Case No. 8774 January 1998	Allegheny Power System DQE, Inc.	Maryland	Dept. of Natural Resources MD Energy Administration	Merger Issues
198.	Docket No. U-20925 (SC) March 1998	Entergy Louisiana, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
199.	Docket No. U-22092 (SC) March 1998	Entergy Gulf States, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
200.	Docket Nos. U-22092 (SC) and U-20925(SC) May 1998	Entergy Gulf States and Entergy Louisiana	Louisiana	Commission Staff	Standby Rates
201.	Docket No. WR98010015 May 1998	NJ American Water Co.	New Jersey	Ratepayer Advocate	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
202.	Case No. 8794 December 1998	Baltimore Gas & Electric Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
203.	Case No. 8795 December 1998	Delmarva Power & Light Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
204.	Case No. 8797 January 1998	Potomac Edison Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
205.	Docket No. WR98090795 March 1999	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
206.	Docket No. 99-02-05 April 1999	Connecticut Light & Power	Connecticut	Attorney General	Stranded Costs
207.	Docket No. 99-03-04 May 1999	United Illuminating Company	Connecticut	Attorney General	Stranded Costs
208.	Docket No. U-20925 (FRP) June 1999	Entergy Louisiana, Inc.	Louisiana	Staff	Capital Structure
209.	Docket No. EC-98-40-000 et. al. May 1999	American Electric Power/ Central & Southwest	FERC	Arkansas PSC	Market Power Mitigation
210.	Docket No. 99-03-35 July 1999	United Illuminating Company	Connecticut	Attorney General	Restructuring
211.	Docket No. 99-03-36 July 1999	Connecticut Light & Power Co.	Connecticut	Attorney General	Restructuring
212.	WR99040249 Oct. 1999	Environmental Disposal Corp.	New Jersey	Ratepayer Advocate	Rate of Return
213.	2930 Nov. 1999	NEES/EUA	Rhode Island	Division Staff	Merger/Cost of Capital
214.	DE99-099 Nov. 1999	Public Service New Hampshire	New Hampshire	Consumer Advocate	Cost of Capital Issues
215.	00-01-11 Feb. 2000	Con Ed/NU	Connecticut	Attorney General	Merger Issues
216.	Case No. 8821 May 2000	Reliant/ODEC	Maryland	Dept. of Natural Resources	Need for Power/Plant Operations
217.	Case No. 8738 July 2000	Generic	Maryland	Dept. of Natural Resources	DSM Funding
218.	Case No. U-23356 June 2000	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Fuel Prudence Issues Purchased Power

	Docket Number	Utility	Jurisdiction	Client	Subject
219.	Case No. 21453 et. al July 2000	SWEPCO	Louisiana	PSC Staff	Stranded Costs
220.	Case No. 20925 (B) July 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
221.	Case No. 24889 August 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
222.	Case No. 21453 et. al. February 2001	CLECO	Louisiana	PSC Staff	Stranded Costs
223.	P-00001860 and P-0000181 March 2001	GPU Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
224.	CVOL-0505662-S March 2001	ConEd/NU	Connecticut Superior Court	Attorney General	Merger (Affidavit)
225.	U-20925 (SC) March 2001	Entergy Louisiana	Louisiana	PSC Staff	Stranded Costs
226.	U-22092 (SC) March 2001	Entergy Gulf States	Louisiana	PSC Staff	Stranded Costs
227.	U-25533 May 2001	Entergy Louisiana/ Gulf States	Louisiana Interruptible Service	PSC Staff	Purchase Power
228.	P-00011872 May 2001	Pike County Pike	Pennsylvania	Office of Consumer Advocate	Rate of Return
229.	8893 July 2001	Baltimore Gas & Electric Co.	Maryland	MD Energy Administration	Corporate Restructuring
230.	8890 September 2001	Potomac Electric/Conectiv	Maryland	MD Energy Administration	Merger Issues
231.	U-25533 August 2001	Entergy Louisiana / Gulf States	Louisiana	Staff	Purchase Power Contracts
232.	U-25965 November 2001	Generic	Louisiana	Staff	RTO Issues
233.	3401 March 2002	New England Gas Co.	Rhode Island	Division of Public Utilities	Rate of Return
234.	99-833-MJR April 2002	Illinois Power Co.	U.S. District Court	U.S. Department of Justice	New Source Review

	Docket Number	Utility	Jurisdiction	Client	Subject
235.	U-25533 March 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Nuclear Uprates Purchase Power
236.	P-00011872 May 2002	Pike County Power & Light	Pennsylvania	Consumer Advocate	POLR Service Costs
237.	U-26361, Phase I May 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Purchase Power Cost Allocations
238.	R-00016849C001 et al. June 2002	Generic	Pennsylvania	Pennsylvania OCA	Rate of Return
239.	U-26361, Phase II July 2002	Entergy Louisiana/ Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
240.	U-20925(B) August 2002	Entergy Louisiana	Louisiana	PSC Staff	Tax Issues
241.	U-26531 October 2002	SWEPCO	Louisiana	PSC Staff	Purchase Power Contract
242.	8936 October 2002	Delmarva Power & Lt.	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
243.	U-25965 November 2002	SWEPCO/AEP	Louisiana	PSC Staff	RTO Cost/Benefit
244.	8908 Phase I November 2002	Generic	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
245.	02S-315EG November 2002	Public Service Co. of Colorado	Colorado	Fed. Executive Agencies	Rate of Return
246.	EL02-111-000 December 2002	PJM/MISO	FERC	MD PSC	Transmission Ratemaking
247.	02-0479 February 2003	Commonwealth Edison	Illinois	Dept. of Energy	POLR Service
248.	PL03-1-000 March 2003	Generic	FERC	NASUCA	Transmission Pricing (Affidavit)
249.	U-27136 April 2003	Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
250.	8908 Phase II July 2003	Generic	Maryland	Energy Admin. Dept. of Natural Resources	Standard Offer Service
251.	U-27192 June 2003	Entergy Louisiana and Gulf States	Louisiana	LPSC Staff	Purchase Power Contract Cost Recovery

	Docket Number	Utility	Jurisdiction	Client	Subject
252.	C2-99-1181 October 2003	Ohio Edison Co.	U.S. District Court	U.S. Department of Justice et. al.	Clean Air Act Compliance Economic Impact (Report)
253.	RP03-398-000 December 2003	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
254.	8738 December 2003	Generic	Maryland	Energy Admin Department of Natural Resources	Environmental Disclosure (oral only)
255.	U-27136 December 2003	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Purchase Power Contracts
256.	U-27192, Phase II October/December 2003	Entergy Louisiana & Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
257.	WC Docket 03-173 December 2003	Generic	FCC	MCI	Cost of Capital (TELRIC)
258.	ER 030 20110 January 2004	Atlantic City Electric	New Jersey	Ratepayer Advocate	Rate of Return
259.	E-01345A-03-0437 January 2004	Arizona Public Service Co.	Arizona	Federal Executive Agencies	Rate of Return
260.	03-10001 January 2004	Nevada Power Co.	Nevada	U.S. Dept. of Energy	Rate of Return
261.	R-00049255 June 2004	PPL Elec. Utility	Pennsylvania	Office of Consumer Advocate	Rate of Return
262.	U-20925 July 2004	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Capacity Resources
263.	U-27866 September 2004	Southwest Electric Power Co.	Louisiana	PSC Staff	Purchase Power Contract
264.	U-27980 September 2004	Cleco Power	Louisiana	PSC Staff	Purchase Power Contract
265.	U-27865 October 2004	Entergy Louisiana, Inc. Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contract
266.	RP04-155 December 2004	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
267.	U-27836 January 2005	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Power plant purchase and cost recovery
268.	U-199040 et al. February 2005	Entergy Gulf States/ Louisiana	Louisiana	PSC Staff	Global Settlement, Multiple rate proceedings

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	Docket Number	Utility	Jurisdiction	Client	Subject
269.	EF03070532 March 2005	Public Service Electric and Gas	New Jersey	Ratepayers Advocate	Securitization of Deferred Costs
270.	05-0159 June 2005	Commonwealth Edison	Illinois	Department of Energy	POLR Service
271.	U-28804 June 2005	Entergy Louisiana	Louisiana	LPSC Staff	QF Contract
272.	U-28805 June 2005	Entergy Gulf States	Louisiana	LPSC Staff	QF Contract
273.	05-0045-EI June 2005	Florida Power & Lt.	Florida	Federal Executive Agencies	Rate of Return
274.	9037 July 2005	Generic	Maryland	MD. Energy Administration	POLR Service
275.	U-28155 August 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Independent Coordinator of Transmission Plan
276.	U-27866-A September 2005	Southwestern Electric Power Co.	Louisiana	LPSC Staff	Purchase Power Contract
277.	U-28765 October 2005	Cleco Power LLC	Louisiana	LPSC Staff	Purchase Power Contract
278.	U-27469 October 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Avoided Cost Methodology
279.	A-313200F007 October 2005	Sprint (United of PA)	Pennsylvania	Office of Consumer Advocate	Corporate Restructuring
280.	EM05020106 November 2005	Public Service Electric & Gas Co.	New Jersey	Ratepayer Advocate	Merger Issues
281.	U-28765 December 2005	Cleco Power LLC	Louisiana	LPSC Staff	Power plant certification, financing, rate plan
282.	U-29157 February 2006	Cleco Power LLC	Louisiana	LPSC Staff	Storm Damage Financing
283.	U-29204 March 2006	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Purchase power contracts
284.	A-310325F006 March 2006	Alltel	Pennsylvania	Office of Consumer Advocate	Merger, Corporate Restructuring

BEFORE THE STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BOARD OF PUBLIC UTILITIES

I/M/O THE JOINT PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF AN INCREASE IN GAS RATES, DEPRECIATION RATES FOR GAS PROPERTY, AND FOR CHANGES IN TARIFF FOR GAS SERVICE, B.P.U. N.J., NO. 13 GAS PURSUANT TO N.J.S.A. 48:2-18, 48:2-21 AND 48:2-21.1)	))))))))	**BPU DKT. NO. GR05100845** **OAL DKT. NO. PUC-1747-06**

SCHEDULES ACCOMPANYING THE
TESTIMONY OF MATTHEW I. KAHAL
ON BEHALF OF THE
NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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BPU Docket No. GR05100845
Schedule MIK-1
BPU Docket No. GR05100845

Filed: June 15, 2006

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Rate of Return Summary [5]
September 30, 2005

Capital Type	Balance (Million $)	% of Total	Cost Rate	Weighted Cost
Long -Term Debt[6]	$3,188	49.52%	6.19%	3.07%
Short-Term Debt[7]	143	2.22	4.80	0.11
Preferred Stock	80	1.24	5.03	0.06
Customer Deposits	43	0.67	2.94	0.02
Common Equity	2,984	46.35	9.50	4.40
Total	$6,438	100.0%	--	7.66%

[5] Source: Schedule ANS-37, R1
[6] Restore $322 million of long-term debt scheduled to mature within one year. Since the effective yield for this debt is more expensive than the claimed embedded cost of debt, this results in an increase in the effective embedded cost rate to 6.19%.
[7] Average balance of short-term debt for the 24 months ending February 2006. Source: RAR-ROR-4, 5.

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Trends in Capital Costs

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
1992	3.0%	7.0%	3.5%	8.7%
1993	3.0	5.9	3.0	7.6
1994	2.6	7.1	4.3	8.3
1995	2.8	6.6	5.5	7.9
1996	3.0	6.4	5.0	7.8
1997	2.3	6.4	5.1	7.6
1998	1.6	5.3	4.8	7.0
1999	2.2	5.7	4.7	7.6
2000	3.4	6.0	5.9	8.2
2001	2.9	5.0	3.5	7.8
2002	1.6	4.6	1.6	7.4
2003	1.9	4.1	1.0	6.6
2004	2.7	4.3	1.4	6.2
2005	3.4	4.3	3.0	5.6

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Trends in Capital Costs (Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2002				
January	1.1%	5.0%	1.7%	7.7%
February	1.1	4.9	1.7	7.5
March	1.5	5.3	1.8	7.8
April	1.6	5.2	1.7	7.6
May	1.2	5.2	1.7	7.5
June	1.1	4.9	1.7	7.4
July	1.5	4.7	1.7	7.3
August	1.8	4.3	1.6	7.2
September	1.5	3.9	1.6	7.1
October	2.0	3.9	1.6	7.2
November	2.2	4.1	1.3	7.1
December	2.4	4.0	1.2	7.1
2003				
January	2.6%	4.1%	1.2%	7.1%
February	3.0	3.9	1.2	6.9
March	3.0	3.8	1.1	6.8
April	2.1	4.0	1.1	6.6
May	2.1	3.6	1.1	6.4
June	2.1	3.7	0.9	6.2
July	2.1	4.0	0.9	6.6
August	2.2	4.5	1.0	6.8
September	2.3	4.3	1.0	6.6
October	2.0	4.3	0.9	6.4
November	1.8	4.3	1.0	6.4
December	1.8	4.3	0.9	6.3
2004				
January	1.9%	4.2%	0.9%	6.2%
February	1.7	4.1	0.9	6.2
March	1.7	3.8	0.9	6.0
April	2.3	4.4	0.9	6.4
May	3.1	4.7	1.0	6.6
June	3.3	4.7	1.3	6.5
July	3.0	4.5	1.4	6.3
August	2.7	4.3	1.5	6.1
September	2.5	4.1	1.6	6.0
October	3.2	4.1	1.8	5.9
November	3.5	4.2	2.1	6.0
December	3.3	4.2	2.2	5.9

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Trends in Capital Costs (Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2005				
January	3.0%	4.2%	2.4%	5.8%
February	3.0	4.2	2.6	5.6
March	3.1	4.5	2.8	5.8
April	3.5	4.3	2.8	5.6
May	2.8	4.1	2.9	5.5
June	2.5	4.0	3.0	5.4
July	3.2	4.2	3.3	5.5
August	3.6	4.3	3.5	5.5
September.	4.7	4.2	3.5	5.5
October	4.3	4.5	3.8	5.8
November	3.5	4.5	4.0	5.9
December	3.4	4.5	4.0	5.8
2006				
January	4.0%	4.4%	4.3%	5.8%
February	3.6	4.6	4.5	5.8
March	3.4	4.7	4.6	6.0
April	3.5	5.0	4.7	6.3
May	--	5.1	4.8	--

Source: Economic Report of the President, Mergent's Bond Record, Federal Reserve Statistical Release, Consumer Price Index Summary.

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Listing of the Comparable Gas Utility Companies

	Company	Safety Rating	Financial Strength	Beta	2005 Common Equity Ratio*
(1)	AGL Resources	2	B++	0.90	48.1%
(2)	Atmos Energy	2	B+	0.70	42.3
(3)	Cascade Natural	3	B+	0.80	40.6
(4)	Keyspan Corp.	2	B++	0.85	53.3
(5)	LaClede Group	2	B+	0.80	51.8
(6)	New Jersey Resources	2	B++	0.80	58.0
(7)	Nicor, Inc.	3	A	1.15	62.6
(8)	NW Natural Gas	1	A	0.70	53.0
(9)	Peoples Energy	2	B++	0.85	47.2
(10)	Piedmont Natural	2	B++	0.75	58.6
(11)	South Jersey Ind.	2	B++	0.65	55.1
(12)	Southwest Gas	3	B	0.80	37.5
(13)	UGI Corp.	2	B+	0.85	41.7
(14)	WGL Corp.	1	A	0.80	58.6
	Average	**2.1**	**--**	**0.81**	**50.6%**

* The common equity ratio excludes short-term debt (and current maturities of long-term debt). Inclusive of total debt, the common equity ratio averages 42.2 percent.

Source: Value Line Investment Survey, March 17, 2006.

PUBLIC SERVICE ELECTRIC & GAS COMPANY

	Company	Safety Rating	Financial Strength	Beta	2005 Common Equity Ratio*
(1)	C.H. Energy	1	A	0.80	58.0%
(2)	Consolidated Edison	1	A++	0.65	49.5
(3)	Duquesne Light Holdings	4	B	0.85	36.4
(4)	Energy East Corp.	2	B++	0.85	41.5
(5)	Northeast Utilities	3	B+	0.85	35.1
(6)	NSTAR	1	A	0.75	41.5
(7)	PEPCO Holdings, Inc.	3	B	0.90	42.0
(8)	UIL Holdings	3	B+	0.85	53.0
	Average	**2.3**	**--**	**0.81**	**44.6%**

* Common equity ratio excludes short-term debt (including current maturities of long-term debt) but it includes transition bonds.

Source: Value Line Investment Survey, March 17, 2006.

PUBLIC SERVICE ELECTRIC & GAS COMPANY

DCF Summary for
Gas Utility Company Group

(1)	Dividend yield (November 2005 - April 2006)	4.18%[1]
(2)	Adjusted yield ((1) x 1.025)	4.3%
(3)	Long-term Growth Rate	4.7 - 5.2[2]
(4)	Total Return ((2) + (3))	9.0 - 9.5%
(5)	Flotation Adjustment	0.00%
(6)	Cost of equity ((4) + (5))	9.25%
Recommendation		9.5%

[1] Schedule MIK-4, page 2 of 4

[2] Schedule MIK-4, page 3 of 4

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Dividend Yield for the Gas Utility Group
(November 2005 - April 2006)

	Company	November	December	January	February	March	April	Average
(1)	AGL Resources	4.2%	4.3%	4.1%	4.1%	4.1%	4.2%	4.17%
(2)	Atmos	4.7	4.8	4.8	4.8	4.8	4.7	4.77
(3)	Cascade	4.7	4.9	4.8	4.9	4.9	4.7	4.82
(4)	Keyspan	5.4	5.2	5.2	4.6	4.6	4.6	4.93
(5)	LaClede	4.6	4.7	4.4	4.2	4.1	4.2	4.37
(6)	New Jersey Res.	3.4	3.4	3.2	3.2	3.2	3.3	3.28
(7)	Nicor	4.6	4.7	4.5	4.3	4.7	4.7	4.58
(8)	Northwest Nat.	4.0	4.0	3.9	4.0	3.9	4.0	3.97
(9)	Peoples Energy	6.1	6.2	5.9	5.9	6.1	6.0	6.03
(10)	Piedmont	3.9	3.8	3.8	3.7	4.0	3.9	3.85
(11)	South Jersey	3.1	3.1	3.1	3.1	3.3	3.4	3.18
(12)	Southwest Gas	3.1	3.1	3.0	2.9	2.9	3.0	3.00
(13)	UGI	3.1	3.3	3.1	3.0	3.2	3.1	3.13
(14)	WGL	4.4	4.4	4.3	4.3	4.4	4.6	4.40
	Average	**4.24%**	**4.28%**	**4.15%**	**4.07%**	**4.16%**	**4.17%**	**4.18%**

Source: Month-ending dividend yields from Standard & Poors Stock Guide, December 2005-May 2006 editions.

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Project Five-Year Earnings Share Growth Rates for
Gas Utility Companies

	Company	Standard & Poors	First Call	Zacks	Value Line	Average
(1)	AGL Resources	5%	5.0%	4.5%	4.0%	4.63%
(2)	Atmos	5	5.8	5.5	7.0	5.83
(3)	Cascade	3	4.0	--	8.5	5.17
(4)	Keyspan	4	4.0	3.2	1.5	3.18
(5)	LaClede	--	4.3	--	7.0	5.65
(6)	N.J. Resources	5	5.5	6.0	4.5	5.25
(7)	NICOR	4	3.3	3.5	4.0	3.70
(8)	NW Natural	5	5.0	5.3	7.0	5.58
(9)	Peoples	4	4.9	4.0	0.5	3.35
(10)	Piedmont	4	4.2	5.2	6.0	4.85
(11)	South Jersey	5	6.0	5.7	7.0	5.93
(12)	Southwest Gas	--	--	6.0	8.5	7.25
(13)	UGI	8	8.0	7.3	5.5	7.20
(14)	WGL	4	3.5	4.0	2.0	3.83
	Average	**4.67%**	**4.88%**	**5.02%**	**5.21%**	**5.07%**

Source: Value Line Investment Survey, March 17, 2006.
Standard & Poors Earnings Guide, April 2006.
Zacks growth rates from MSN Money website, April 2006.
Thomson First Call from Yahoo Finance website, April 2006.

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Other Value Line Growth Measures
For Gas Utility Companies

	Company	Dividend Growth	Book Value Growth	2009-2011 Earnings Reinvestment Growth
(1)	AGL	6.5%	6.0%	5.0%
(2)	Atmos	2.0	5.0	5.0
(3)	Cascade	0.5	10.5	3.0
(4)	Keyspan	2.5	4.0	2.5
(5)	LaClede	2.0	5.0	6.5
(6)	N.J. Resources	4.5	8.0	7.5
(7)	Nicor	1.5	3.5	3.5
(8)	NW Natural	4.0	3.5	3.8
(9)	Peoples	1.0	(1.5)	2.5
(10)	Piedmont	5.5	3.5	4.5
(11)	South Jersey	6.0	6.0	6.0
(12)	Southwest Gas	0.0	3.0	6.5
(13)	UGI Corp.	5.0	10.5	7.5
(14)	WGL Corp.	2.0	4.0	4.5
	Average	**3.07%**	**5.07%**	**4.82%**

Source: Value Line Investment Survey, March 17, 2006.

PUBLIC SERVICE ELECTRIC & GAS COMPANY

DCF Summary for
Electric Utility Group

(1)	Dividend yield (November 2005 - April 2006)	4.80%[(1)]
(2)	Adjusted yield ((1) x 1.025)	4.9%
(3)	Long-term Growth Rate	4.6 - 5.0
(4)	Total Return ((2) + (3))	9.5 - 9.9%[(2)]
(5)	Flotation Adjustment	0.00%
(6)	Cost of equity ((4) + (5))	9.5-9.9%
Recommendation		9.5%

[(1)]Schedule MIK-5, page 2 of 4

[(2)]Schedule MIK-5, page 3 of 4

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Dividend Yield for the Electric Utility Group
(November 2005-April 2006)

	Company	November	December	January	February	March	April	Average
(1)	C.H. Energy	4.6%	4.7%	4.6%	4.4%	4.5%	4.6%	4.57%
(2)	Con Ed	5.0	4.9	4.9	5.0	5.3	5.3	5.07
(3)	Duquesne	5.9	6.1	5.6	5.8	6.1	5.9	5.90
(4)	Energy East	4.9	5.1	4.7	4.6	4.8	4.8	4.82
(5)	North East U.	3.8	3.6	3.5	3.6	3.6	3.5	3.60
(6)	NSTAR	4.1	4.0	4.2	4.1	4.2	4.4	4.17
(7)	PEPCO	4.6	4.5	4.5	4.4	4.6	4.5	4.52
(8)	UIL	6.0	6.3	6.0	5.6	5.5	5.2	5.77
	Average	**4.86%**	**4.90%**	**4.75%**	**4.68%**	**4.83%**	**4.78%**	**4.80%**

Source: Month-ending dividend yields from Standard & Poors Stock Guide, December 2005-May 2006 editions.

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Projected Five-Year Earnings Per Share
Growth Rates for Electric Utility Companies

	Company	Standard & Poors	First Call	Zacks	Value Line	Average
(1)	C.H. Energy	--	--	--	3.5	3.50%
(2)	Con Ed	3	3.5	4.2	2.5	3.30
(3)	Duquesne	--	--	--	4.5	4.50
(4)	Energy East	4	4.0	4.5	4.0	4.13
(5)	NE Utilities	8	8.5	8.7	11.0	9.05
(6)	NSTAR	5	5.0	5.0	3.5	4.63
(7)	PEPCO	6	4.0	3.4	5.5	4.73
(8)	UIL	11	10.5	18.0	0.5	10.00
	Average	**5.50%**	**5.92%**	**7.30%**	**4.38%**	**5.48%***

* Average growth rate is distorted by the unusual 10.0% for UIL. Excluding UIL, growth rates average 4.83%. Also, the median growth rate is 4.57%

Source Value Line Investment Survey, March 3, 2006.
Standard & Poors Earnings Guide, April 2006.
Zacks growth rates from MSN Money website, April 2006.
First Call growth rates from Yahoo Finance website, April 2006.

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Other Value Line Growth Measures
For Electric Utility Companies

	Company	Dividend Growth	Book Value Growth	2009-2011 Earnings Reinvestment Growth
(1)	C.H. Energy	0.5%	2.0%	3.0%
(2)	Consolidated Edison	1.0	3.0	2.5
(3)	Duquesne Light	0.0	5.0	5.0
(4)	Energy East	5.0	2.5	3.0
(5)	Northeast U.	9.0	2.5	5.0
(6)	NSTAR	4.0	5.5	4.5
(7)	PEPCO	6.0	2.5	4.5
(8)	UIL	0.0	0.5	0.0
	Average	**3.18%**	**2.93%**	**3.44%**

Source: Value Line Investment Survey, March 3, 2006.

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Capital Asset Pricing Model Study

A. Model Specification

$Ke = R_F + \beta (R_m - R_F)$, where

Ke = cost of equity

R_F = return on risk free asset

Rm = expected stock market return

B. Data Inputs

R_F = 4.75-5.25% (20-year Treasury bond yield for most recent six months)

Rm = 10-12% (see page 3 of this schedule)

Beta = 0.81 (Source: Value Line Investment Survey)

C. Model Calculations

Low end: Ke = 4.75% + 0.81 (10.0-4.75) = 9.00%

Midpoint: Ke = 5.0% + 0.81 (11.0-5.0) = 9.86%

Upper end: Ke = 5.25 + 0.81 (12.0-5.25) = 10.71%

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Comparisons of Reported Betas
for Gas Distribution Companies

	Company	Value Line Betas	Standard & Poors Betas	Yahoo Finance Beta
(1)	AGL	0.90	0.50	0.20
(2)	Atmos	0.70	0.17	0.80
(3)	Cascade	0.80	--	1.05
(4)	Keyspan	0.85	0.42	0.35
(5)	LaClede	0.80	0.37	1.22
(6)	New Jersey Res.	0.80	0.11	0.60
(7)	Nicor	1.15	0.73	0.69
(8)	NW Natural	0.70	0.09	0.80
(9)	Peoples	0.85	0.37	0.97
(10)	Piedmont	0.75	--	0.68
(11)	South Jersey	0.65	0.33	0.50
(12)	Southwest Gas	0.80	0.26	0.36
(13)	UGI Corp.	0.85	0.28	0.80
(14)	WGL Corp.	0.80	0.26	0.71
	Average	**0.81%**	**0.32%**	**0.70%**

Source: Value Line Investment Survey, March 17, 2006.
Standard & Poors, Stock Reports, April/May 2006.
Yahoo Finance website (“key statistics”), May 2006.

PUBLIC SERVICE ELECTRIC & GAS COMPANY

Stock Market Return Estimates

(1) Ibbotson Associates Historical Return

Ke = 6.6% + 5.0% = 11.6% (arithmetic mean)

Ke = 5.0% + 5.0 = 10.0% (geometric mean)

(Source: Ibbotson Associates, 2004)

(2) Ibbotson/Chen Supply Side Model

Ke = 5.9% + 5.0% = 10.9%

(Ibbotson/Chem estimate an arithmetic risk premium of 5.9% for stocks over risk free Treasury bonds over the time period, 1926-2000, excluding the effects of rising P/E ratios. Source: Stock Market Return in the Long Run: Participating in the Real Economy, 2002, Roger G. Ibbotson and Peng Chen published in Financial Analysts Journal.)

(3) Industrial Composite DCF

Ke = 2.1% + 8.0 = 10.1% (based on five years earnings growth rates)

Ke = 2.1% + 10.0% = 12.1% (based on the average of earnings growth and earnings retention growth)

(Value Line Industrial Composite, Value Line "Selection and Opinion," May 19, 2006, earnings per share growth rate is 8.0%, dividends per share of 8.0%, book value per share of 6.0% and an earnings retention growth rate of 12.0%.)

(4) Five-Year Earnings Projection (S&P 500)

Ke = 8.0% + 1.9% = 9.9% (Zacks projections)

Ke = 10.6% + 1.9% = 12.5% (First Call projections)

(Source: MSN Money for Zacks [June 2006] and
Yahoo Finance for First Call [April 2006].)